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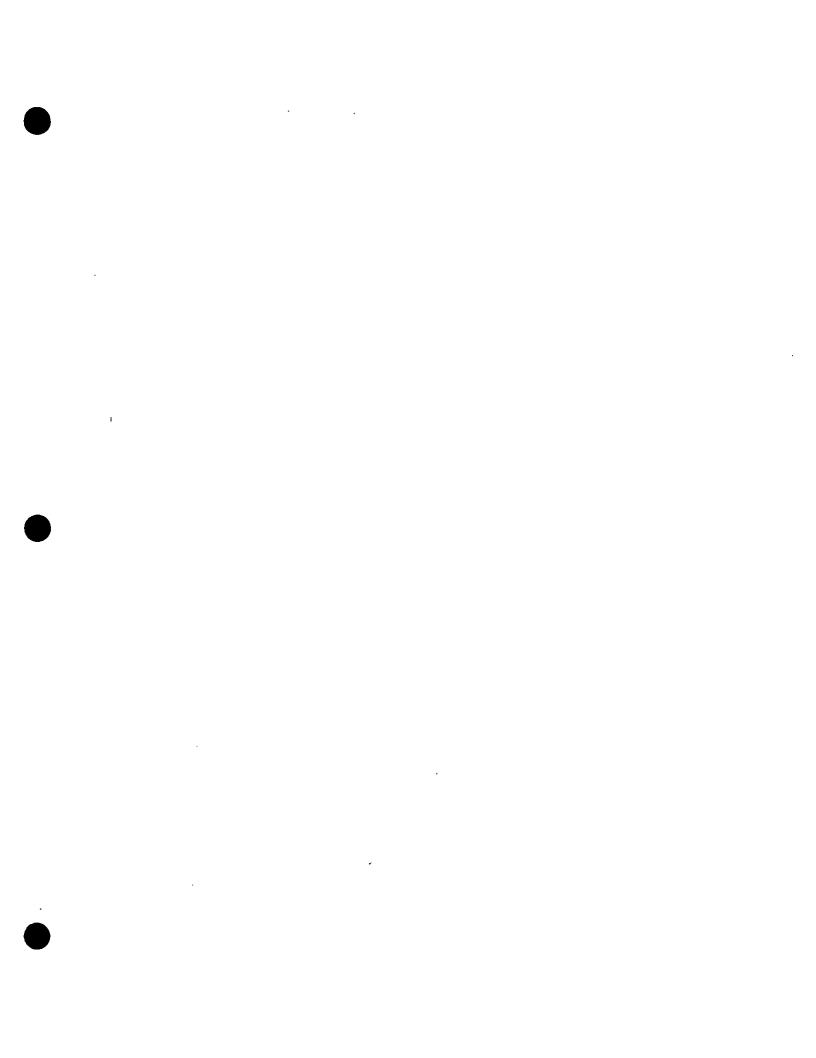
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BEFORE THE PUBLIC UTILITI OF THE STATE OF		MOD BLIC	л
In the Matter of the Application of)		
HAWAII ELECTRIC LIGHT COMPANY, INC.)) DOCK	KET NO. (05-0315
For Approval of Rate Increases and Revised Rate Schedules and Rules.))		

DIVISION OF CONSUMER ADVOCACY'S DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS

Book <u>2</u> of <u>2</u>

February 21, 2007



PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY AND EXHIBITS

OF

STEVEN C. CARVER

ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Rate Base Update, Prepaid Pension Asset, Keahole Adjustments, T&D and A&G Corrections, T&D Training Costs, T&D Labor Costs

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CA-T-3 DOCKET NO. 05-0315

,	Description of Exhibits				
CA-300	Summary of Qualifications				
CA-301	Summary of Previously Filed Testimony				
CA-302	Historical Comparison of Pension Costs, Contributions & Prepaid				
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CA-303	Historical Analysis of Pension Costs Included in Revenue Requirement				
CA-304	CA Proposed Pension Cost Tracking Mechanism				
CA-305	Pension Tracker: Comments & Clarifications				
CA-306	Proposed Pension Tracking Mechanism – Illustrations				
CA-307	Keahole (as recorded) Construction Costs (6/91-11/98)				
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CA-312	Letter from Warren Lee to the Commission, November 1991				
CA-313	Consumer Advocate SOP, Docket No. 7048				

DIRECT TESTIMONY OF STEVEN C. CARVER

- PLEASE STATE YOUR NAME AND BUSINESS ADDRESS. 2 A. My name is Steven C. Carver. My business address is 740 NW Blue
- 3 Parkway, Suite 204, Lee's Summit, Missouri 64086.

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Q.

- 5 Q. WHAT IS YOUR PRESENT OCCUPATION?
- 6 Α. I am a principal in the firm Utilitech, Inc., which specializes in providing 7 consulting services for clients who actively participate in the process 8 surrounding the regulation of public utility companies. Our work includes the 9 review of utility rate applications, as well as the performance of special 10 investigations and analyses related to utility operations, cost allocation and 11 ratemaking issues.

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- ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING? 13 Q.
- 14 Α. Hawaii Electric Light Company, Inc. (hereinafter "HELCO" or "Company") filed 15 an application seeking the Public Utilities Commission of the State of Hawaii's 16 ("Commission" or "HPUC") approval for an overall increase in the tariff rates 17 and charges under which it provides regulated electric service on the island of 18 Hawaii. The HPUC opened Docket No. 05-315 to review and address this 19 application.

Utilitech was retained by the Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (hereinafter "Consumer Advocate," or "CA") to review and respond to that rate case filing and to prepare direct testimony for filing with this Commission regarding the issues identified during the course of our review. Consequently, I am appearing on behalf of the Consumer Advocate.

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5 Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

Generally, my responsibilities in this docket encompass the review and evaluation of various elements of rate base and operating income included within the overall revenue requirement, focusing on several functional expense categories (i.e., transmission and distribution, administrative and general, depreciation) as well as various elements of rate base (i.e., plant additions and retirements, Keahole CT-4/CT-5, prepaid pension asset). As a result, I address various adjustments to rate base and operating income. specifically CA Adjustments B-1, B-2, B-7, B-8, C-14, C-15, C-17 through C-19, and C-21, and jointly sponsor the Consumer Advocate's proposed capital structure (Schedule D) with Mr. David Parcell (CA-T-4). The additional ratemaking adjustments proposed by the Consumer Advocate, which I do not sponsor, are separately addressed in the direct testimony of Mr. Michael Brosch (CA-T-1). The revenue requirement effect of the various Consumer Advocate adjustments and recommendations are reflected within the Consumer Advocate's Joint Accounting Schedules (Exhibit CA-101).

1 I. EDUCATION AND EXPERIENCE.

- 2 Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?
- 3 A. I graduated from State Fair Community College, where I received an
- 4 Associate of Arts Degree with an emphasis in Accounting. I also graduated
- from Central Missouri State University with a Bachelor of Science Degree in
- 6 Business Administration, majoring in Accounting.

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- 8 Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE IN THE
- 9 FIELD OF UTILITY REGULATION.
- My entire professional career has been associated with the regulation of 10 Α. 11 public utilities. From 1977 to 1987, I was employed by the Missouri Public 12 Service Commission ("MoPSC") in various professional auditing positions, 13 including a promotion by the Missouri Commissioners to the position of Chief 14 Accountant in April 1983. Since my employment with Utilitech in June 1987, I 15 have been associated with various regulatory projects on behalf of clients in 16 multiple State jurisdictions (Arizona, California, Florida, Hawaii, Kansas, 17 Illinois, Iowa, Indiana, Mississippi, Missouri, Nevada, New Mexico, New York, 18 Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia and 19 Wyoming) and have conducted revenue requirement and special studies 20 involving various regulated industries (i.e., electric, gas, telephone and water).
- 21 Additional information regarding my professional experience and
- qualifications are summarized in Exhibits CA-300 and CA-301, which have
- been prepared for this purpose.

1 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION IN
2 PROCEEDINGS THAT INVOLVED HELCO OR ITS SUBSIDIARIES?

Α.

Yes. I have prepared testimony in two prior proceedings involving (Docket Nos. 98-0013 and 99-0207) primarily relating to elements of HELCO's recently added generating units — Keahole CT-4 and CT-5. Mr. Michael Brosch, also of Utilitech, and I prepared and presented revenue requirement recommendations on behalf of the Consumer Advocate in the 1994 and 2005 rate cases (i.e., Docket Nos. 7700 & 04-0113, respectively) of Hawaiian Electric Company ("HECO"), HELCO's parent company. In addition, I have prepared testimony in several other Hawaii regulatory proceedings, including: Kauai Electric, a Division of Citizens Communications Company (Docket No. 94-0097); GTE Hawaiian Telephone Company, Inc. (fna Verizon Hawaii, nka Hawaiian Telcom) (Docket No. 94-0298); The Gas Company (Docket No. 00-0309); as well as a self-insured property damage reserve generic proceeding (Docket No. 95-0051), in which HELCO and its affiliates participated.

Finally, I have assisted the Consumer Advocate in its analysis of the acquisition of The Gas Company by Citizens Communications Company from Broken Hill Proprietary Company, Ltd. (Docket No. 97-0035) and the subsequent acquisition of The Gas Company, a Division of Citizens Communications Company by K-1 USA Ventures, Inc. (Docket No. 03-0051), as well as the analysis of the sale of Verizon Hawaii to entities controlled by the Carlyle Group (Docket No. 04-0140).

1 II. EXECUTIVE SUMMARY.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RESPONSIBILITIES IN THIS
 3 PROCEEDING?

My testimony addresses various issues surrounding the reasonableness of HELCO's proposed rate increase and discusses specific rate base and operating income adjustments that I will generally refer to as "CA Adjustments" or "CA Schedules," which are set forth within a separate bound volume identified as Exhibit CA-101. These CA Adjustments and CA Schedules affect various operations and maintenance ("O&M") expense and rate base components upon which base rates are to be determined in the instant proceeding.

The ratemaking areas that I address include: (a) the update and correction of various elements of rate base, (b) the inclusion of the prepaid pension asset in rate base, (c) the proposed disallowance of AFUDC and certain project costs associated with the Keahole generation additions, (d) adoption of certain HELCO revisions and corrections for T&D and A&G expense, and (e) the adjustment of T&D labor expense to recognize average 2006 employee levels. The specific adjustments are more fully listed in the index to my testimony.

A.

1 Q. HOW WILL YOU IDENTIFY AND REFER TO THE INDIVIDUAL 2 ACCOUNTING ADJUSTMENTS?

As discussed by Mr. Brosch, the rate base and operating income adjustments have been numbered sequentially, but separately, beginning with the number "one." In order to distinguish the first rate base adjustment from the first operating income adjustment, the adjustment number is preceded by a reference to the schedule on which the adjustment was posted. So, the first rate base adjustment would be referenced as CA Adjustment B-1 and the first operating income adjustment would be identified as CA Adjustment C-1. Mr. Brosch and I may use the words "schedule" and "adjustment" interchangeably when referring to the individual adjustments proposed by the Consumer Advocate.

Α.

Q. DO THE JOINT ACCOUNTING SCHEDULES PROVIDE CALCULATION
DETAIL SUPPORTING EACH CONSUMER ADVOCATE ADJUSTMENT?

A. Yes. The joint accounting schedules contain individual adjustment "schedules" that typically show the quantification of each adjustment, with footnote reference to supporting documentation. Virtually all information relied upon by the Consumer Advocate in developing these adjustments was supplied by HELCO in response to written discovery or contained in Company workpapers. Consequently, the adjustment schedules generally refer to relevant data sources, already in the Company's possession.

- 1 Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.
- 2 A. My testimony is arranged by topical section, following the table index
- 3 presented previously. This index identifies the specific areas I address in
- 4 testimony and references the testimony pages as well as any related
- 5 adjustment support located in the joint accounting schedules.

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- 7 III. RATE BASE UPDATE AND CORRECTIONS.
- 8 Q. WHAT ARE CA ADJUSTMENTS B-1 AND B-2?
- 9 A. CA Adjustments B-1 and B-2 (Exhibit CA-101) update and revise the
- 10 Company's 2006 rate base forecast to recognize actual plant additions and
- 11 actual balances for the prepaid pension asset, contributions in aid of
- 12 construction ("CIAC") and customer advances.

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- 14 Q. PLEASE EXPLAIN THE COMPANY'S QUANTIFICATION OF RATE BASE?
- 15 A. In general terms, HELCO-1601 represents the Company's estimate of the
- various elements of rate base (i.e., net plant in service, inventories, prepaid
- pension asset, accumulated deferred income taxes, customer advances, etc.)
- at of December 31, 2005 and at December 31, 2006. These beginning and
- end of year amounts were then averaged to determine the "Average Rate
- 20 Base" balance included in HELCO's quantification of overall revenue
- 21 requirement.

The December 31, 2006, projections included estimated changes for the 2006 test year.

2 ESTIMATE BASED ON THE AVAILABILITY OF MORE CURRENT ACTUAL INFORMATION? 3 4 Α. Yes. When the Company's test year forecast and revenue requirement filing 5 was prepared, little information existed with regard to the actual charges to, or 6 actual completion dates of individual construction projects. More specifically, 7 the Company's original filing incorporated the forecasted 2006 plant additions 8 set forth on HELCO-WP-1401, representing four pages of detailed estimates 9 of construction expenditures and completion dates by individual project. 10 Throughout the course of this proceeding, numerous information requests 11 were submitted by the Consumer Advocate seeking additional information on 12 individual projects, including updates to the cost of the projects, revisions to 13 completion dates and the status of any related customer or third party funds. Because of delays in the procedural schedule in this proceeding, 14 15

WAS THE ADJUSTMENT TO THE COMPANY'S 2006 PLANT ADDITION

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HELCO was able to provide actual (i.e., "preliminary") 2006 plant additions by project in response to CA-SIR-51. Rather than attempt to compile piecemeal correcting adjustments to the Company's original plant addition forecast, CA Adjustment B-1 replaces the forecast additions set forth on HELCO-WP-1401 with actual detailed 2006 project additions.

CA Adjustment B-1 represents the net adjustment to the Company's 2006 plant additions. Since all additions, by definitions, occurred in 2006, the balances in Column (C) at December 31, 2005, are "zero." Column (D) compares the Company's forecast plant additions with the actual 2006 plant

additions, by plant category, to determine the net adjustment to year-end plant balances. Column (E) then averages the beginning and ending points for computing the test year average adjustment. It is this average adjustment amount in Column (E) that is included in plant in service.

A.

6 Q. PLEASE DESCRIBE THE ITEMS ON CA ADJUSTMENT B-2, OTHER THAN
7 PLANT ADDITIONS.

As previously discussed, HELCO's estimated average test year rate base represents the simple average of the estimated balances at December 31, 2005 and December 31, 2006. Lines 15 through 30 of CA Adjustment B-2 adjusts the year-end balances for other rate base elements (i.e., prepaid pension asset, contributions in aid of construction and customer advances) to recognize the impact of actual 2006 activity and revise the Company's original forecast balances at December 31, 2006.

It should be noted that certain rate base items, such as fuel inventories and accumulated deferred income taxes, are not part of this adjustment because these rate base elements are separately adjusted by the Consumer Advocate (see CA Adjustments B-3, B-4 and B-5), while the recorded year-end balance of other rate base items are believed to have not changed materially.

Q.	WHAT IS THE PURPOSE OF THE PREPAID PENSION ASSET				
	ADJUSTMENT APPEARING AT LINES 1 THROUGH 4 of CA ADJUSTMENT				
	B-2?				
A .	On its books and records, HELCO has recorded a prepaid pension asset				
	representing the cumulative difference between the pension costs and				
	pension contributions. While I will discuss the prepaid pension asset in a				
	subsequent testimony section, CA Adjustment B-2 simply revises the				
	year-end balance to reflect HELCO's update for December 31, 2006, as				
	provided in response to CA-IR-464 (page 60).				
Q.	HOW WAS THE UPDATE TO THE COMPANY'S CONTRIBUTIONS IN AID				
	OF CONSTRUCTION ("CIAC") RATE BASE OFFSET DETERMINED AT				
	LINES 5 THROUGH 10?				
A.	Using a similar procedure as discussed for the plant additions update, the test				
	year activity for CIAC was revised to recognize the actual 2006 collections				
	HELCO provided in response to CA-SIR-51.				
	In late 2006, HELCO completed and closed to plant in service various				
	construction projects for which the Company had either not yet collected, or				
	not yet billed, related CIAC or customer advances due from customers or				
	other third parties (e.g., State or County for utility relocations). In early				
	February 2007, the Consumer Advocate verbally requested additional				
	information regarding these amounts during a teleconference on HELCO's				
	A.				

response to CA-SIR-51. At the time this testimony was prepared, discussions

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were continuing with the Company with respect to the identification and quantification of such amounts. Consequently, Line 8 of CA Adjustment B-2, "Adjustments for Post-TY Collections for 2006 Plant Additions," serves as a placeholder to recognize any such additional amounts, once they are provided.

Α.

Q. IF RATE BASE IS BEING UPDATED TO RECOGNIZE ACTUAL PLANT
ADDITIONS THAT OCCURRED IN 2006, WHY DO YOU BELIEVE THAT
RATE BASE SHOULD RECOGNIZE ANY ADDITIONAL CIAC THAT MIGHT
BE COLLECTED SUBSEQUENT TO 2006?

In a word, matching. At the time HELCO commits to an individual construction project, it is known whether the customer or a third party has committed to participate in funding a portion of the cost of that project. The Company's construction authorization documents typically will disclose the existence of such commitments and may even contain estimates of the amounts to be collected. Such amounts, however, may be fixed or subject to true-up once actual project expenditures become know. If the cost of these completed construction projects are to be included in rate base, particularly projects that were completed late in 2006, it is only reasonable that rate base recognize any additional offsets for CIAC or customer advances related to these plant additions, even if HELCO's billings or collections are delayed into 2007.

- 1 Q. WAS THE SAME APPROACH EMPLOYED FOR CUSTOMER ADVANCES,
- 2 AS WAS USED FOR CIAC, WHICH APPEARS AT LINES 11-16 OF
- 3 CA ADJUSTMENT B-2?
- 4 A. Yes. It should be noted that Line 14 of CA Adjustment B-2, "Adjustments for
- 5 Post-TY Collections for 2006 Plant Additions," also serves as a placeholder to
- 6 recognize such additional customer advance amounts, once they are
- 7 provided by HELCO.

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- 9 Q. TO YOUR KNOWLEDGE, HAS HELCO ACTUALLY QUANTIFIED UPDATES
- 10 AND REVISIONS TO ITS VARIOUS RATE BASE EXHIBITS IN ORDER TO
- 11 REFLECT ACTUAL 2006 ACTIVITY AND BALANCES AT DECEMBER 31,
- 12 2006?
- 13 A. During discussions with HELCO representatives in early February 2006, the
- 14 Company had not yet decided whether to revise its 2006 rate case test year
- to reflect actual activity and balances (e.g., gross plant, accumulated
- depreciation, etc.), whether to propose a partial update to actual amounts with
- 17 revised forecasts for the remainder of 2006 (e.g., actuals through October
- and revised forecast for November-December), or whether to proceed with its
- original forecasts. I informed the Company of the Consumer Advocate's
- 20 planned approach to recognize actual plant additions and other related items,
- 21 when the available actual data resulted in more reasonable valuations than
- 22 outdated forecast information.

1	IV.	PREPAID PENSION ASSET & PENSION TRACKING MECHANISM.
2	Q.	IS THE CONSUMER ADVOCATE PROPOSING AN ADJUSTMENT TO
3		HELCO'S PROPOSED INCLUSION OF THE PENSION ASSET IN RATE
4		BASE?
5	A.	No.
6		
7	Q.	IF THE CONSUMER ADVOCATE IS NOT OPPOSING HELCO'S
8		INCLUSION OF THE PENSION ASSET IN RATE BASE, WHAT IS THE
9		PURPOSE OF THIS TESTIMONY?
10	A.	Since the Consumer Advocate has opposed similar recommendations in
11		other rate proceedings (e.g., Docket No. 04-0113), the basis for the
12		Consumer Advocate's non-opposition in the instant docket should be clearly
13		communicated. By submitting this testimony, the Consumer Advocate
14		intends to avoid any misinterpretation of its current position in the pending
15		HELCO rate case in any other proceedings involving a utility's request to
16		include prepaid pension asset in the test year rate base.
17		
18	Q.	WHY IS THE CONSUMER ADVOCATE NOT OPPOSING THE INCLUSION
19		OF THE PREPAID PENSION ASSET IN HELCO'S 2006 TEST YEAR RATE
20		BASE?
21	A.	In prior rate proceedings, I have sponsored testimony opposing, allowing and
22		partially allowing the prepaid pension asset in rate base. In each proceeding,
23		I have prepared historical analyses to assess whether ratepayers, through

utility rates, have or have not participated in the reduced pension costs that gave rise to the recording of the prepaid pension asset. The analysis prepared in this case supports the Company's requested rate base inclusion of the prepaid pension asset, after considering the estimated net benefit ratepayers have received since FAS87-determined² net periodic pension costs ("NPPC") were first included in utility rates in Docket No. 6432.³

As an alternative recommendation, the Consumer Advocate has prepared a pension cost tracking mechanism for consideration by the Commission. If a balanced mechanism were implemented for regulatory purposes, ratemaking issues associated with rate base inclusion of the prepaid pension asset should become a thing of the past. Because the Consumer Advocate has estimated that HELCO ratepayers have historically received a net benefit relating to the difference between the amount of NPPC historically included within and presumed to be collected through rates *versus* the amount of actual contributions to the pension fund, a separate amortization of that net benefit (i.e., the prepaid pension asset), would be

Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standards No. 87 ("FAS87").

According to HECO's response to CA-IR-134, as revised by the response to CA-IR-270, FAS87 based NPPC was first included in utility rates in Docket No. 6432. Although a 1990 test year was employed in that rate case, the effective date of the Commission's order was March 15, 1991.

appropriate <u>only</u> if the proposed pension tracking mechanism is adopted.⁴ In other words, the net benefit amortization is <u>not</u> recommended by the Consumer Advocate in the absence of the pension tracking mechanism.

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Q. WHAT IS THE AMOUNT OF THE PREPAID PENSION ASSET, GROSS OF
 THE ADIT RESERVE, THAT HELCO PROPOSES TO INCLUDE IN TEST
 YEAR RATE BASE?

In direct testimony, Company witness Fujioka (HELCO T-9) proposed to include in rate base an estimated average prepaid pension asset balance of about \$14.2 million, gross of the related ADIT reserve balance.⁵ HELCO subsequently revised its test year forecast of the average prepaid pension asset to about \$14.1 million, in response to discovery submitted by the Consumer Advocate.⁶

Although HELCO adopted FAS87 for accounting purposes in 1987, the Company's utility rates did not explicitly include FAS87-determined net periodic pension costs until the issuance of the Commission's March 1991

Because the pension tracker mechanism is an alternate recommendation, Exhibit CA-101 does not show an adjustment to achieve such an amortization. Instead, a new amortization adjustment would need to be quantified in the event a tracker mechanism is adopted by the Commission.

⁵ HELCO T-9, p. 108 & HELCO-920.

See HELCO response to CA-IR-464, p. 60.

decision in Docket No. 6432.⁷ As indicated by the analysis set forth on Exhibit CA-303, the estimated amount of total NPPC included in rates is about \$7.8 million less than the total NPPC actually recorded by the Company since the 1991 ratemaking recognition of FAS87. Consequently, ratepayers have received sufficient benefits through utility rates to support the rate base inclusion of the recorded prepaid pension asset balance, net of the related ADIT reserve balance, as requested by HELCO in this proceeding.

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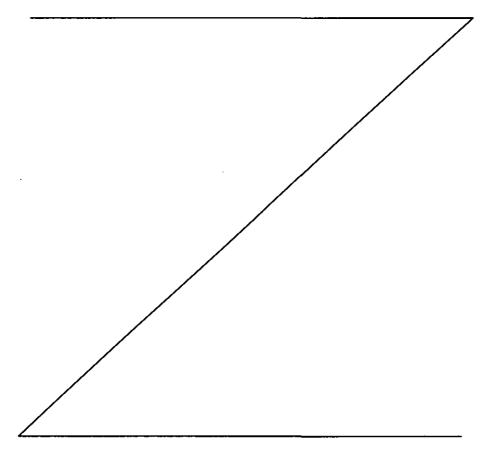
Q, IF THE ANALYSIS SET FORTH ON EXHIBIT CA-303 HAD SHOWN THAT
THE NPPC INCLUDED IN UTILITY RATES WAS HIGHER THAN ACTUAL
NPPC, WOULD YOU HAVE PROPOSED TO INCLUDE THE PREPAID
PENSION ASSET IN RATE BASE?

Depending on the results of such an analysis, it is possible that I would have recommended that only a portion of or none of the recorded prepaid pension asset should be included in rate base. Obviously, the results of such an analysis would be dependent on the unique facts and circumstances of each utility at the time the analysis is prepared. In HELCO's current case, the key factor causing the analysis to support rate base inclusion of the prepaid pension asset is the magnitude of the amount of negative NPPC embedded in

HELCO response to CA-IR-141 (FAS87 adopted for accounting purposes in 1987); HELCO T-9, p. 93, and HELCO responses to CA-IR-134 & CA-IR-270 (FAS87 adopted for ratemaking purposes in Docket No.-6432).

the rates resulting from the last rate case, in relation to actual NPPC and pension contributions during the following years (i.e., 2002-2006).

More specifically, it is only during the last three years (2004-2006) that the cumulative ratepayer benefit became material enough to support rate base inclusion. Stated another way, the facts and circumstances as they existed in 2004 would not have supported rate base inclusion of the prepaid pension asset, but does now support rate base inclusion in 2006. So, the facts and circumstances relevant to the amount of NPPC embedded in utility rates will yield a different, but consistent, conclusion in any given rate case and for any particular utility.



1 Q. IN HECO'S 2005 RATE CASE (DOCKET NO. 04-0113), WHICH IS STILL 2 AWAITING A FINAL COMMISSION DECISION, YOU FILED TESTIMONY 3 ON BEHALF OF THE CONSUMER ADVOCATE OPPOSING HECO'S 4 PROPOSED INCLUSION OF THE PENSION ASSET IN RATE BASE. WHY 5 ARE YOU NOW RECOMMENDING THAT THE COMMISSION ALLOW 6 HELCO TO INCLUDE THE PREPAID PENSION ASSET BALANCE IN RATE 7 BASE? As discussed in my direct testimony in HECO's 2005 test year rate case.8 I 8 Α. 9 recommended that the average test year balance of the prepaid pension 10 asset and the related accumulated deferred income tax ("ADIT") reserve 11 balance be excluded from rate base. Based on the historical facts and 12 circumstances unique to the accounting and ratemaking treatment of HECO's 13 NPPC, I concluded that "ratepayers [had] received absolutely no tangible 14 benefit from HECO having recorded cumulative pension costs at levels less 15 than pension contributions" and concluded that "the pension asset should be 16 properly excluded from rate base."9 My recommendation in Docket

HECO Docket No. 04-0113, Direct Testimony of CA witness Steven C. Carver (CA-T-2), pp. 7-26. Since the Consumer Advocate is not opposing HELCO's proposed inclusion of the pension asset in rate base, for purposes of this case, a conscious attempt was made to streamline the pension accounting discussion without compromising the explanation of the rationale for the Consumer Advocate's position. For additional background information regarding pension accounting, please see the referenced testimony and post hearing briefs filed in Docket No. 04-0113.

⁹ HECO Docket No. 04-0113, Carver Direct Testimony (CA-T-2), p. 21.

No. 04-0113 was based on the specific facts as they pertained to HECO, consistent with the test year in that proceeding.

In comparison, HELCO's accounting and ratemaking history surrounding NPPC is decidedly different from that of HECO. Because of HELCO's distinct ratemaking and accounting history, I recommend that the prepaid pension asset be included in rate base in this docket. Thus, while my approach and analysis of this issue is identical to that which I undertook in the recent HECO case, the differentiating facts indicate that the prepaid pension asset balance on HELCO's books and records should appropriately be included in rate base – for purposes of this case.

Unlike HELCO's last rate case wherein negative NPPC of about \$3 million was included in rates, the 2006 test year forecast now includes positive NPPC of about \$2.8 million. Consequently, the propriety of including the prepaid pension asset in rate base in HELCO's next rate case may or may not be appropriate.

Q.

Α.

HAVE YOU ADDRESSED ISSUES ASSOCIATED WITH PENSION COSTS
OR THE PREPAID PENSION ASSET IN PAST RATE PROCEEDINGS?

Yes. Some jurisdictions have committed significant resources to evaluate, adjust and modify various assumptions (e.g., discount rate, assumed return on plan assets, amortization of gains and losses, etc.) included in the actuarial studies used to determine annual costs recorded by the utility and recognized in operating expense. Regulators in other jurisdictions have also

expended significant resources evaluating the reasonableness of utility claims that a pension (or OPEB) asset or liability should be recognized in rate base.

I have sponsored testimony in various jurisdictions concerning the proposed inclusion of a pension asset in rate base. In most of those proceedings, the prepaid pension asset that the utility sought to include in rate base arose as a result of normal pension cost accounting — not because the utility was out-of-pocket for the "asset" balance.

In a still pending Missouri rate case, AmerenUE proposed a pension tracking mechanism, which is very similar to the mechanism I am currently proposing as an alternative recommendation on behalf of the Consumer Advocate. Basically, this mechanism attempts to step around the inconsistencies between pension accounting and ratemaking treatment so as to ensure that utility ratepayers do not over-pay or under-pay and the utility does not over-collect or under-collect pension costs over time.

- Q. OTHER THAN THE RECENT HECO RATE CASE, HAVE YOU PREVIOUSLY RECOMMENDED THE COMPLETE ELIMINATION OF THE PENSION ASSET FROM RATE BASE?
- A. Yes, with two exceptions. In a recent Arizona proceeding, an update of my pension analyses presented in earlier proceedings supported, for the first time, the inclusion of a prepaid pension asset in rate base. In the pending AmerenUE rate case in Missouri (MoPSC Case No. ER-2007-0002), I filed testimony, on behalf of the Missouri Attorney General, supporting the

Company's proposed pension tracking mechanism, with additional comment and clarification.

Other than those proceedings, my pension asset analyses resulted in recommendations excluding the pension asset from rate base, based on the facts and circumstances unique to each utility. Absent a demonstration that ratepayers have materially participated in the cumulative pension credits or reduced pension costs comprising the prepaid pension asset, my analyses have consistently questioned whether the alleged benefits were instead enjoyed by investors, not ratepayers

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A. BACKGROUND REGARDING PENSION COST ACCOUNTING.

12 Q. PLEASE DESCRIBE THE EVENTS OR CIRCUMSTANCES GIVING RISE
 13 TO THE PENSION ASSET.

In December 1985, the FASB issued FAS87, which provided guidance as to how companies would recognize pension costs for financial statement reporting purposes. As a result of FAS87, the FASB determined that pension costs reported in public financial statements would not automatically be equal to the pension fund contribution, breaking the historical linkage between financial reporting of net periodic pension costs (expense and capital) and pension contributions. In general terms, ¹⁰ FAS87 required companies to

Pension costs recorded for financial statement purposes pursuant to FAS87 are also referred to as "net periodic pension costs" or "NPPC."

record either a pension asset or pension liability for the difference between accrual basis pension costs and the amount of any contributions to the pension fund.

Α.

5 Q. HOW DID THE ISSUANCE OF FAS87 AFFECT THE PENSION COSTS
6 RECORDED ON THE COMPANY'S FINANCIAL STATEMENTS?

Subsequent to the adoption of FAS87, HELCO's net periodic pension costs continued to equal the amounts contributed to the pension fund in each year until 1997. 11 Beginning in 1998, the contributions to the fund exceeded the NPPC amount recorded for financial statement purposes, thereby causing HELCO to record a relatively modest pension asset. In 1998, the Company recorded positive NPPC and made no contribution to the external trust fund, causing the prepaid pension asset to swing slightly negative (i.e., indicative of a pension liability) for one year.

In 2000-2002, however, HELCO recorded annual NPPC amounts that were materially negative (i.e., pension credits), rather than the "positive" amounts recorded in prior years. Although HELCO made no contribution to the pension fund in these years, "zero" still exceeded the negative pension costs and the prepaid pension asset account grew significantly. From 2003 through 2006, the Company recorded positive NPPC in each of the four years and made contributions to the pension fund in all years but for 2006. It is the

¹¹ HELCO's pension asset accounting is summarized on Exhibit CA-302.

accumulation of contributions to the pension fund in excess of FAS87 determined pension costs that caused the pension asset balance to grow to an average of \$14.1 million in the forecast test year. (Exhibit CA-302.)

Q.

YOU INDICATED THAT THE PREPAID PENSION ASSET BALANCE GREW SIGNIFICANTLY DURING CALENDAR YEARS 2000, 2001 AND 2002 WHEN NPPC WAS NEGATIVE AND CONTRIBUTIONS WERE "ZERO." COULD YOU EXPLAIN HOW MATERIAL THESE YEARS OF NEGATIVE NPPC WERE TO THE OVERALL BALANCE OF THE PREPAID PENSION ASSET?

11 A. The

The Company's revised average test year balance for the prepaid pension asset is \$14.1 million. Of this balance, \$9.1 million, or about 64% of the total, is directly attributable to the negative NPPC amounts recorded during the period 2000-2002.¹²

For clarification purposes to avoid any misinterpretation, the negative NPPC amounts and the resulting impact on the prepaid pension asset represent non-cash transactions – unless and until those negative costs are recognized in setting utility rates. Only then do the non-cash transactions become cash affecting. And, only then should any portion of the prepaid pension asset be included in rate base, limited to the extent of cumulative benefits actually enjoyed by ratepayers.

1 Q	. HAS THIS COMMISSION ISSUED A RECENT ORDER THAT YOU BELIEVE
2	IS RELEVANT TO THE MATTER OF CASH VERSUS NON-CASH
3	TRANSACTIONS?
4 A.	. Yes. In Decision and Order No. 23223, 13 the Commission denied the join
5	application of HECO, HELCO and MECO for approval to record a regulatory
6	asset in lieu of any charges to Accumulated Other Comprehensive Income
7	Citing to page 10 of the Consumer Advocate's Statement of Position, the
8	following statement by the Commission appears at page 29:
9 10 11	In other words, the regulatory asset created under the FASB requirement for pension accounting does not constitute a monetary expenditure or the application of cash.
12 13	While the regulatory asset referenced by the Commission is not identical to
14	the prepaid pension asset HELCO seeks to now include in rate base, it is a
15	close cousin. The following excerpt from page 10 of the Consumer
16	Advocate's Statement of Position, reproduced in footnote 25 at page 17 of
17	Decision and Order No. 23223, further explains the concept of cash versus
18	non-cash transactions:
19 20 21 22 23 24 25 26	If it is determined that the Pension Plan is underfunded, the [HECO] Companies expect ratepayers to provide the [HECO] Companies with a return on the shortfall (i.e., the reconciling balance which they seek to record as a regulatory asset). This is in spite of the fact that the [HECO] Companies are not out-of-pocket for even a dime of that balance. It should be made clear that while the term "asset" might be used to describe the balance, the "asset" is not a revenue generating

27 28 item (unless the Commission allows it to be one by including the

asset in rate base). It also does not represent a cash

Decision and Order No. 23223 (Docket No. 05-0310) was issued on January 26, 2007.

1 2 3 4 5 6 7 8 9		expenditure or application of cash, nor is it an item that is used to provide utility service. The regulatory asset that would be created under the FASB requirements for pension accounting simply exists in lieu of a charge to AOCI representing a reconciling difference between the actuarially calculated obligations (PBO) of the [HECO] Companies and the available funds of the Pension Plan. As indicated previously, changes in NPPC levels only become cash				
10		affecting when ratepayers receive explicit benefits through the				
11		ratemaking process.				
12						
13		B. PROPOSED HELCO APPROACH.				
14	Q.	WHAT IS THE BASIS FOR THE COMPANY'S CLAIM THAT THE PREPAID				
15		PENSION ASSET SHOULD BE INCLUDED IN RATE BASE?				
16	Α.	At pages 93 and 108, HELCO T-9 generally summarizes the Company's				
17		basis for seeking rate base inclusion as follows:				
18 19 20 21 22 23 24 25 26 27		Including the prepaid pension asset in rate base is proper because: (1) rate base inclusion is consistent with the ratemaking treatment of the pension expense under the guidance set forth in SFAS 87, (2) the prepaid pension asset reflects a prudent investment, funded by investors, that is used or useful in providing electric utility service, (3) the prepaid pension asset benefits the ratepayers, and (4) other jurisdictions have allowed a prepaid pension asset to be included in rate base.				

1 Q. DO YOU AGREE WITH POINTS ADDRESSED BY HELCO T-9 TO
2 SUPPORT THE RATE BASE INCLUSION OF THE PREPAID PENSION
3 ASSET FOR RATEMAKING PURPOSES?

Α.

No. First, FAS87 provides accounting guidance with respect to the financial accounting disclosure of pension costs, related assets and liabilities. FAS87 neither prescribes nor imposes any regulatory guidance or authoritative ratemaking treatment for the prepaid pension asset.

Second, while the prepaid pension asset was recorded pursuant to FAS87, this asset is not directly analogous to other types of assets included on the Company's balance sheet that are recognized for rate base purposes. Unlike the Company's investment in other assets (e.g., fuel oil inventory, prepaid casualty insurance, electric poles, customer meters, overhead lines, etc.), HELCO did not expend any funds to purchase or acquire the prepaid pension asset, which is nothing more than the cumulative difference between FAS87 based NPPC and actual contributions to the pension fund.

Consistent with my position in the recent HECO rate case, rate base inclusion of the recorded balance of the prepaid pension asset would only be appropriate if it can be reasonably demonstrated that reduced FAS87 pension costs, in a cumulative amount at least equal to the prepaid pension asset sought to be included in rate base, have been flowed through to the benefit of utility ratepayers.¹⁴ I obviously disagree with HELCO T-9 on this issue.

HECO Docket No. 04-0113, Carver Direct Testimony (CA-T-2), p. 17.

 Third, while the potential for ratepayer benefits does exist, particularly when negative NPPC is involved, whether said benefits have actually been enjoyed by ratepayers is unique to each regulated utility and can change over time. The mere fact that a utility may have recorded negative NPPC or that NPPC was less than fund contributions in some years does not automatically translate into substantial ratepayer benefits in the form of decreased costs.

It is not uncommon for regulators to address various issues associated with accounting changes (e.g., transition from pay-as-you-go to FAS106 accrual accounting for OPEB costs, capitalization of software development costs), cost deferrals (e.g., storm damage, demand-side management costs), amortization requests (e.g., depreciation reserve deficiency, workforce reduction program costs) or tracking mechanisms (e.g., fuel adjustment clause, demand-side management costs) that deviate from this general framework. If the mere act of recording a transaction meant that ratepayers symmetrically funded increases and benefited from decreases in expense, there would be no need for the many cost deferral, cost tracker or cost amortization issues that frequently arise in utility regulation – most often initiated by utility applicants.

The NPPC and the prepaid pension asset are no different. While negative NPPC, or pension credits, have been periodically recorded by some utilities since the late 1980's, the question should focus on whether and to what extent HELCO's ratepayers have benefited from the reduced pension costs, in comparison to pension contributions, to support rate base inclusion

of the pension asset. If ratepayers have not benefited from the reduced level of pension costs, as compared to contributions, then the Company and its investors are the only remaining parties that could have benefited from the reduced costs through higher earnings than would have otherwise been achieved.

While the Company has proposed to include the pension asset in rate base, HELCO has provided no factual support to quantify the extent of any ratepayer benefits to the detriment of HELCO's investors. Rate base inclusion is appropriate only if it can be reasonably demonstrated that reduced FAS87 pension costs, including the pension credits, on a cumulative basis in an amount at least equal to the prepaid pension asset to be included in rate base have been flowed through to the benefit of HELCO's ratepayers. However, in the current case, it is the analyses prepared by the Consumer Advocate, not HELCO that have provided factual support for inclusion of the pension asset in rate base.

Α.

Q. DO YOU BELIEVE THAT RATEPAYERS RECEIVE THE BENEFIT OF PENSION CREDITS, OR REDUCED PENSION COSTS, MERELY AS A RESULT OF RECORDING THE NEGATIVE, OR REDUCED, PENSION COSTS?

No. The mere recording of NPPC, whether positive or negative in amount, at levels lower than pension contributions does not conclusively demonstrate "who" (ratepayers or investors) may have funded, or benefited from, the lower

recorded pension costs. Since HELCO has sought rate base treatment of the pension asset, the Company should bear a substantial burden to demonstrate that such inclusion is proper.

In describing ratepayer benefits, HELCO T-9 (page 113) refers to \$3 million of negative NPPC recognized in A&G expense in HELCO's 2000 test year rate case (Docket No. 99-0207). Other than a historical comparison of pension costs and contributions comprising the prepaid pension asset balance set forth on HELCO-920,¹⁵ the Company has not provided any quantification of the cumulative benefits ratepayers have received to support the proposed rate base inclusion of the prepaid pension asset. Furthermore, the Company's reference to the fact that negative NPPC was recognized in A&G expense in HELCO's last rate case does not justify full inclusion of the recorded prepaid pension asset in rate base. Such reference or analysis is woefully deficient as it fails to comprehensively consider the amount of FAS87-determined NPPC collected in rates versus total NPPC recorded by HELCO.

Q. THE FOURTH POINT RAISED BY HELCO T-9 TO SUPPORT THE RATE
BASE INCLUSION OF THE PREPAID PENSION ASSET IS THAT "OTHER

HELCO-920 has been updated to reflect actual 2006 activity by HELCO's response to CA-IR-464. p. 60.

JURISDICTIONS HAVE ALLOWED A PREPAID PENSION ASSET IN RATE
BASE." DO YOU HAVE ANY COMMENTS ON THIS POINT?

Yes. HELCO T-9 does not discuss the treatment of other jurisdictions, other than to observe that this subject was discussed in the opening and reply briefs of the parties in HECO's 2005 test year rate case (Docket No. 04-0113). As indicated in the response to CA-IR-124, HELCO did not undertake any additional research for the instant docket, instead relying on the research conducted in HECO's 2005 test year rate case.

With respect to HECO's research in other jurisdictions, it is of particular note that, during the December 2005 hearings on the pension asset issue, HECO witness Tayne Sekimura (HECO T-16) referred to a pension tracking mechanism of some potential interest. The mechanism was set forth in a settlement agreement in a then recent Empire District Electric Company rate case (Missouri Case No. ER-2004-0570). Although HECO T-16 indicated that the tracking mechanism had some appeal to the Company, more research and review would be required to determine whether HECO would find such a mechanism to be acceptable. The referenced Missouri pension tracking mechanism serves as the basis for the Consumer Advocate's proposed tracking mechanism in this docket.

Α.

1 2 3		C.	CONSUMER ALLOWANCE.	ADVOCATE'S	PROPOSED	RATE	BASE
4	Q.	YOU	PREVIOUSLY	INDICATED THAT	HELCO'S INC	CLUSION	OF THE
5		AVEF	RAGE PREPAID	N RATE BASE	IS APPR	OPRIATE	
6		BECA	AUSE OF THE	ESTIMATED NET	BENEFIT RA	TEPAYER	S HAVE
7		RECE	EIVED AS A RES	SULT OF THE NPP	C COSTS INC	LUDED IN	UTILITY
8		RATE	ES. IS THAT CO	RRECT?			
9	A.	Yes.	Exhibit CA-303	3 provides an estin	nate of the ne	et benefit	HELCO's
10		ratepa	ayers have recei	ved as a result of the	ne FAS87 NPP	C costs in	icluded in
11		utility	rates. Although	h the current proced	eding is HELC	O's sixth	rate case
12		since	FAS87 based N	IPPC was first reco	gnized for rate	making pu	rposes in
13		Dock	et No. 6432, Exh	nibit CA-303 takes in	nto account the	effect of I	regulatory
14		lag by	y comparing the	total NPPC included	in utility rates	with the to	tal NPPC
5		record	ded by HELCO o	n an annual basis in	order to evalua	ate and qu	antify the
16		estim	ated net benefit	received by ratepay	ers for purpose	s of quant	tifying the
17		Cons	umer Advocate's	recommended rate I	base allowance		
18							
19	Q.	REFE	ERRING TO EX	KHIBIT CA-303, H	OW DOES T	HE AMO	UNT OF
20		PENS	SION COSTS IN	CLUDED IN HELCO	o's cost of	SERVICE	IN PAST
21		RATE	CASES COM	PARE TO THE A	CTUAL NPPC	SUBSEC	QUENTLY
22		RECO	ORDED BY THE	COMPANY?			
23	A.	Althou	ugh it is not poss	ible to precisely quar	ntify the amount	of accumi	ulated net
24		pensi	on recoveries fr	om, or benefits pro	vided to ratep	ayers follo	wing the

adoption of FAS87, it is possible to perform an analysis comparing the various levels of total NPPC included in utility rates with the NPPC subsequently recorded by HELCO, in order to evaluate whether ratepayers have reasonably received any material benefit, thereby supporting all or part of HELCO's proposed rate base treatment.

As demonstrated by Exhibit CA-302, the primary reason that cumulative pension contributions have exceeded the recorded pension costs by \$12.8 million though 2006 is because the financial accounting requirements of FAS87 resulted in HELCO recording significant pension credits (i.e., \$9.1 million) in calendar years 2000-2002. Thus, 64% of the average test year prepaid pension asset, or about 71% of the 2006 year-end prepaid pension asset, is directly attributable to the negative pension costs recorded in calendar years 2000-2002 pursuant to FAS87 financial accounting requirements, which has nothing to do with "who" (ratepayers or investors) provided the monies contributed to the pension fund.

In response to CA-IR-134 and CA-IR-270, HELCO provided the amount of total NPPC included in cost of service in each of the five rate case test years since adoption of FAS87, including the negative \$3 million recognized in the last rate case. Exhibit CA-303 compares the amounts of total NPPC included in rates in each of HELCO's rate cases with the total actual NPPC recorded by the Company, with the difference representing the annual cost or benefit to ratepayers, all else remaining constant. Since the effective date of the Commission's Decision and Order in Docket No. 6432,

ratepayers have received a net relative benefit of approximately \$7.8 million - which supports rate base inclusion of the prepaid pension asset.

Referring to Exhibits CA-302 and CA-303, the entire prepaid pension asset HELCO seeks to include in rate base has arisen since 1999,¹⁷ including about \$9 million of pension credits recorded during the period 2000-2002. However, ratepayers did not explicitly participate in the negative NPPC until February 2001, when Decision and Order No. 18365 (Docket No. 99-0207) became effective. By my estimation, ratepayers have continued to participate in the \$3 million of negative pension credits embedded in current rates through calendar year 2006. Overall, HELCO's ratepayers have sufficiently participated in the NPPC benefits to include the pension asset in rate base.

A.

Q. ARE YOUR CALCULATIONS OF RECOVERIES FROM RATEPAYERS
"EXACT" IN AMOUNT?

No. It is not possible to precisely quantify the "exact" amount of cumulative net pension recoveries from or benefits provided to ratepayers, particularly over the decades predating or following the adoption of FAS87. However, it is reasonable to consider relevant, available information to assess regulatory intent and estimate the amount of cumulative pension costs or credits that might have been reasonably recovered from or otherwise flowed through to

As indicated by Exhibit CA-303, HELCO's revised average pension asset for the 2006 forecast is \$14.1 million. Although Decision and Order No. 10993 (Docket No. 6432) was effective March 15, 1991, the entire prepaid pension asset balance has arisen since 1999.

1		the benefit of ratepayers, in assessing the amount of the prepaid pension
2		asset reasonably includable in rate base.
3		
4	Q.	BY ATTEMPTING TO ASSESS RATEPAYER PARTICIPATION IN THE
5		REDUCED PENSION COSTS RECORDED BY THE COMPANY OVER THE
6		YEARS, ARE YOU SUGGESTING THAT THE COMMISSION ENGAGE IN
7		RETROACTIVE RATEMAKING?
8	A.	No, absolutely not. I do not propose or suggest that HELCO should pay back
9		past excessive profits or recoup past operating losses, as implied by that
10		concept. Instead, the retrospective analysis or review that I propose would
11		solely be used to gauge the extent of benefits received by ratepayers or
12		retained by investors in determining the prepaid pension asset balance that
13		should be included in rate base.
14		
15	Q.	HAS YOUR APPROACH BEEN USED FOR ANY OTHER ELEMENT OF
16		RATE BASE?
17	Α.	No, it has not. However, such a criticism fails to address the key points of
18		concern relative to this issue:
19		Have ratepayers benefited from the pension credits, or recorded
20		NPPC, less than contribution levels?
21		If so, by how much?
22		• Is the cumulative extent of any benefits enjoyed by ratepayers
23		sufficient to include all or part of the pension asset in rate base?

The implementation of FAS87 resulted in a significant shift in accounting method for pension costs from the cash basis to an accrual basis. Because this shift in accounting method has generally caused HELCO to record pension costs at levels significantly less than pension contributions, I believe that it is responsible and reasonable for regulators to question the extent to which ratepayers, not the Company and its investors, have enjoyed the benefits of those pension credits or cumulative NPPC accruals being less than contributions – before allowing the pension asset in rate base.

Since adoption of FAS87, the amount of pension costs and pension credits recorded by HELCO has varied significantly from year-to-year. In between rate cases or in the absence of some mechanism to flow changes in NPPC, or pension credits, through to ratepayers, FAS87 pension accounting can result in differing amounts benefiting ratepayers and increasing utility income and investor returns.

Contrary to any implications otherwise, the evaluation of this issue is <u>not</u> designed, intended nor does it result in a retrospective inquiry of past earnings to impose a surcharge for past under-recoveries or a refund for past over-recoveries. Instead, this approach is designed to evaluate, based on available information, whether it is reasonable to assume that ratepayers have sufficiently enjoyed the benefits of the ever fluctuating NPPC

The amount of NPPC recorded since 1987 has ranged from \$2.7 million in 2006 to \$(3.4) million in 2001 (Exhibit CA-302).

1 (supporting rate base inclusion of some portion of the pension asset) or 2 whether the resulting earnings benefits have been retained by investors 3 (supporting rate base exclusion). 4 Q. DO YOU BELIEVE THAT ALL ELEMENTS OF THE COST OF SERVICE 5 6 INCLUDED IN PAST RATES SHOULD BE RECONCILED WITH CURRENT 7 COST LEVELS TO DETERMINE PROSPECTIVE RATE TREATMENT FOR 8 **EACH ITEM?** 9 As a matter of ratemaking policy, I do not recommend that the Α. No. 10 Commission rely solely on or otherwise reconcile past decisions in 11 establishing cost of service for future periods. However, the consideration of 12 past rate orders is indeed relevant in assessing whether investors have some 13 reasonable claim to inclusion of the pension asset in rate base. As discussed 14 above, I recommend that the Commission include the prepaid pension asset 15 in rate base. 16 17 Q. IN THE 2006 TEST YEAR FORECAST, HAS HELCO ESTIMATED NPPC TO 18 BE POSITIVE OR NEGATIVE AND HOW DOES THAT AMOUNT COMPARE 19 TO THE ESTIMATED PENSION CONTRIBUTION? 20 Α. As indicated in the response to CA-IR-464 (page 60), HELCO estimated the 21 actual 2006 NPPC at about \$2.7 million and indicated that there would be no 22 pension fund contribution in 2006. Consequently, the amount of NPPC 23 included in overall revenue requirement in this proceeding now exceeds the

planned contribution for the 2006 test year. Because NPPC exceeded the amount contributed in 2006, the December 2006 estimated prepaid pension asset balance is now lower than the December 2005 actual balance. If this relationship continues in future years, the prepaid pension asset balance will continue to decline.

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D. CONSUMER ADVOCATE'S ALTERNATIVE PROPOSAL TO IMPLEMENT A PENSION TRACKING MECHANISM.

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Α.

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EARLIER. YOU INDICATED THAT. UNDER THE CONSUMER ADVOCATE'S ALTERNATIVE PROPOSAL, IT WOULD BE APPROPRIATE **AMORTIZE** THE NET PENSION BENEFIT TO RECEIVED RATEPAYERS, WHICH IS AN INTEGRAL ELEMENT OF THE PROPOSED PENSION TRACKING MECHANISM. IS THAT CORRECT?

Yes. The Consumer Advocate has proposed a pension tracking mechanism patterned after similar mechanisms that have been implemented or proposed in electric rate case proceedings before the Missouri Public Service Commission. The pension asset amortization, a form of catch-up amortization, is conditioned on the Commission's adoption of the pension tracking mechanism proposed herein by the Consumer Advocate. In other words, if the pension tracking mechanism is not adopted, the Consumer Advocate's amortization would not be included in overall revenue requirement.

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1 Q. HOW DID YOU BECOME AWARE OF THE PENSION TRACKING
2 MECHANISM DEVELOPED IN MISSOURI?

While I was generally aware that a pension tracking mechanism had been developed and implemented for certain Missouri utility companies, my first opportunity to review the Missouri mechanism was via the stipulations and agreements involving Empire District Electric Company and Kansas City Power & Light Company, which were produced in response to DOD-RIR-36 as part of HECO's jurisdictional research in Docket No. 04-0113. Since HECO's 2005 test year rate case, I have had the opportunity to review the Missouri pension tracking mechanism in greater detail and discuss the mechanics of that mechanism with Missouri Staff personnel as well as an independent actuary that actively participated in the development of said mechanism.

The Missouri Public Service Commission adopted similar pension tracking mechanisms set forth within stipulations and agreements in a rate case filed by Empire District Electric Company (Case No. ER-2004-0570) and in the Kansas City Power and Light Company Experimental Regulatory Plan (Case No. EO-2005-0329). While the specific terms and conditions may be subject to some modification in the pending HELCO rate case, each of these mechanisms is slightly different to account for the unique history and circumstances of each utility.

Α.

2		REVIEW OF THE MISSOURI MECHANISM?
3	A.	Utilitech was retained by the Attorney General on behalf of the State of
4		Missouri to assist in the review of, and to respond to, the revenue requirement
5		filing of Union Electric Company d/b/a AmerenUE (MoPSC Case
6		No. ER-2007-0002). In that proceeding, Mr. C. Kenneth Vogl, an actuary and
7		employee benefits consultant with Towers Perrin, sponsored testimony on
8		behalf of AmerenUE to establish a pension tracking mechanism.19
9		As a result of my participation in the pending AmerenUE rate

WHAT FACTORS CAUSED YOU TO BECOME INVOLVED IN A DETAILED

As a result of my participation in the pending AmerenUE rate proceeding, I sponsored testimony concluding that the tracking mechanism was symmetrical, fair and equitable for both ratepayers and AmerenUE. With this recent background, the Consumer Advocate is presenting, as an alternative recommendation, a similar pension tracking mechanism for the Commission's consideration.

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Q.

Mr. Vogl had been previously retained by Empire District Electric Company in MoPSC Case No. ER-2004-0570 and participated in the development of a similar mechanism set forth in the stipulation and agreement in that proceeding.

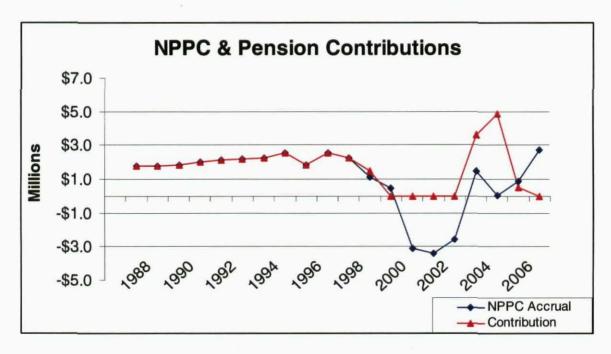
1 Q. PLEASE DESCRIBE THE BASIC PREMISE FOR THE PENSION 2 TRACKING MECHANISM.

Paraphrasing from the Consumer Advocate's Statement of Position ("SOP") recently filed in Docket No. 05-0310,²⁰ pension accounting for public financial disclosure purposes can be very complex. In general terms, pension accounting must consider the requirements of, and interrelationships between, various organizations (e.g., the Financial Accounting Standards Board, the Pension Benefit Guaranty Corporation, the pension fund managers, the Internal Revenue Service, actuarial consultants, etc.) and must consider actual results, forecasted values, and other non-objective measures and factors. If not difficult enough, this complexity is further compounded when additional issues arise relating to proper regulatory accounting for and ratemaking treatment of pension costs.

As summarized on Exhibit CA-302 and depicted on the following chart, HELCO's annual net periodic pension costs and pension contributions were relatively stable during the 1987-1997 period, ranging from \$1.8 million to \$2.5 million. Beginning in 1998, HELCO's NPPC and pension contributions began to fluctuate significantly from year to year.

Α.

On December 8, 2005, Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO") filed an application (HPUC Docket No. 05-0310) seeking Commission approval to record a regulatory asset for any pension liability which would otherwise be charged to accumulated other comprehensive income. On December 8, 2006, the Consumer Advocated filed a detailed Statement of Position responding to this application. See pp. 7-8 of the Consumer Advocate's SOP.



In addition, trust contributions also began to diverge from NPPC beginning in 1998, causing HELCO to record the prepaid pension asset the Company now proposes to include in rate base.

Pension costs have been volatile in recent years, with some utilities recording negative NPPC for a period of time – as did HELCO during 2000-2002. Recent history also documents the ongoing disconnect between NPPC included in setting utility rates from NPPC a utility records/reports for financial statement disclosure purposes and from the utility's actual contributions to its external pension trust fund. While each of these elements may (or may not) be synchronized during a particular utility rate case, the significant volatility that arises between utility rate cases often results in the presentation of complex ratemaking issues in utility rate cases, including regulatory debates about the propriety of rate base treatment of the prepaid pension asset – as in the instant case as well as the 2005 HECO rate case.

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NPPC and pension contributions are volatile and difficult to forecast for ratemaking purposes, particularly in establishing ongoing cost levels. Pension accounting requirements have and are likely to continue to result in significant regulatory issues. The Consumer Advocate's proposed pension tracking mechanism is designed to ensure that, over time, HELCO will collect pension costs from ratepayers in an amount equal to the pension costs recognized for external reporting purposes (i.e., NPPC) and the Company would fund the amount of NPPC to the pension trust.²¹ As a result of the procedure, ratepayers will neither be undercharged nor proposed overcharged for pension costs relative to actual NPPC. Furthermore, the proposed procedure will resolve contentious ratemaking issues associated with the rate base recognition of prepaid pension asset or pension liability balances. In the absence of such a procedure, the volatile changes in NPPC and the continuing disconnect between NPPC and contributions that occur between rate cases may never be accurately reflected in the utility rates paid by HELCO's customers.

FASB's pension accounting requirements (e.g., FAS87, FAS88, FAS158, etc.) were neither designed nor specifically intended to represent a framework for quantifying the amount of pension costs regulated entities should be allowed to recover from their customers. Instead, these

The tracking mechanism also accounts for funding restrictions and/or limitations that limit the utility's ability to make fund contributions equal to NPPC.

pronouncements set forth the required framework for all publicly traded companies to consistently quantify and record net periodic pension costs, pension assets and pension liabilities.

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5 Q. HOW WOULD THIS PENSION TRACKING MECHANISM WORK?

The amount of NPPC included in utility rates and collected by a utility is typically based on actual or forecast test year costs, which precede the effective date of any new rates ordered by the Commission. Once new rates are established, the utility theoretically continues to collect from ratepayers the level of NPPC included in cost of service until rates are changed in the next rate case. During the intervening period, any increases or decreases in actual NPPC and pension contributions occur outside the traditional ratemaking process. As a result, the utility may collect too little or too much NPPC through its rates in relation to actual pension costs and actual contributions. Similarly, the rates paid by utility customers may include too much or too little NPPC. This disconnect between the volatile level of actual NPPC and the amount included in utility rates can significantly impact reported earnings and can further contribute to contentious issues regarding the appropriate amount of prepaid pension asset to be included in rate base, if any. By establishing a procedure to track these cost changes, the amount of NPPC collected in rates will, over time, equal the actual NPPC recorded by the utility and the actual pension fund contributions, thereby avoiding future contentious debates on related issues (i.e., prepaid pension asset).

Exhibit CA-304 contains a detailed description of the mechanics and operations of the proposed tracking procedure. Exhibit CA-305 provides additional clarifying comments, which are intended to minimize confusion about the proposed pension tracking mechanism. Exhibit CA-306 presents a series of illustrations showing how the tracking mechanism would handle different accounting situations that might arise.

While the mechanics and the terminology employed in the ratemaking and accounting discussions set forth in these exhibits might appear complex, the concept embodied in the proposal is straightforward. Stated simply, the proposal is designed to ensure full and complete recovery of all FAS87-determined NPPC costs over time. To the extent NPPC costs recorded during a given rate-effective period exceed or fall short of the level of NPPC costs included in rates, any such over <u>or</u> under recovery of NPPC costs will be deferred for future recovery from or returned to ratepayers, with rate base recognition of any remaining unamortized cash-affecting balance at the time of the next rate case. Further, the proposal envisions that the utility will make annual pension fund contributions equal to the actual NPPC recorded each year, unless limited by ERISA minimum contribution requirements or IRC maximum limitations.

Q. YOU PREVIOUSLY INDICATED THAT HELCO ESTIMATED ACTUAL NPPC OF ABOUT \$2.7 MILLION AND "ZERO" PENSION CONTRIBUTION IN 2006.

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64,674,055

WOULD THIS BE ACCEPTABLE UNDER THE CONSUMER ADVOCATE'S 1 2 PROPOSED PENSION TRACKING MECHANISM? 3 Α. Using 2006 as an example, the pension tracking mechanism would 4 require annual contributions equal to NPPC – or \$2.7 million, using the 2006 5 amounts - assuming no ERISA minimum or IRC maximum limitations. In other words, a key condition of the tracking mechanism is that the utility must 6 7 fund NPPC. Since NPPC is \$2.7 million in 2006, contributions totaling "zero" 8 would be a violation of the tracking mechanism, which would require the utility 9 to fund \$2.7 million. 10 IN 2005 AND 2006, HOW DOES HELCO'S NPPC COMPARE WITH THE 11 Q. 12 ACTUAL AMOUNT OF CONTRIBUTIONS AND THE ERISA MINIMUM AND 13 **IRC MAXIMUM LIMITATIONS?** 14 Α. Using data provided in response CA-IR-464, the following table compares 15 actual NPPC and actual contribution amounts for 2005 and 2006 with the 16 ERISA minimum and IRC maximum contribution limits: 2005 2006 Actual NPPC \$ 875,000 2,744,000 **Actual Contribution** 500.000

17 18 ERISA Minimum

IRC Maximum

In calendar years 2005 and 2006, the actual NPPC amounts fell well within the minimum and maximum contribution range.

Source: CA-IR-464, pp. 6, 7, 51 & 60.

14,519,164

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DOES HELCO MAINTAIN SEPARATE PENSION FUNDS OR ARE HELCO'S 1 Q. 2 CONTRIBUTIONS COMMINGLED WITH THOSE OF ITS AFFILIATES? 3 Α. In the December 8, 2005, Application filed in Docket No. 05-0310, the 4 Companies state that the "assets of the pension plan are commingled for all 5 participating employers." However, the "assets and liabilities of each 6 participating employer are separated for purposes of determining each 7 participating employer's pension costs." So, while the plan assets are 8 commingled for all Companies, it appears that the actuary is able to 9 segregate HELCO's assets for purposes of conducting the actuarial studies 10 required to determine NPPC and compliance with pension funding 11 requirements. 12 IN ITS STATEMENT OF POSITION FILED IN DOCKET NO. 05-0310, THE 13 Q. 14 CONSUMER ADVOCATE OBJECTED TO A JOINT APPLICATION SEEKING APPROVAL OF CERTAIN ACCOUNTING PROCEDURES FOR 15 16 EVENTS RELATED TO PENSION ACCOUNTING. ARE YOU GENERALLY 17 FAMILIAR WITH THAT SOP? Yes. HECO, HELCO and MECO (hereinafter the "Companies") filed a joint 18 Α. 19 application seeking Commission approval to deviate from standard pension 20 accounting by requesting Commission approval to record a regulatory asset 21 pursuant to FAS71, Accounting for the Effects of Certain Types of Regulation,

in lieu of a charge against equity (i.e., accumulated other comprehensive income or "AOCI"), under certain circumstances.^{22 23}

In opposing the Companies' request on various grounds, the Consumer Advocate observed that adoption of their proposal would result in investors having the best of both worlds. When the Companies record a prepaid pension asset pursuant to FAS87, they expect rate base treatment for that asset. When the Pension Benefit Obligation exceeds the fair value of the assets in the pension trust fund, the Companies proposed to record a regulatory asset, instead of the charge against the AOCI, to offset the minimum pension liability. While the Companies did not seek an explicit finding regarding the ratemaking of the new regulatory asset in Docket No. 05-0310, the Companies proposal did indicate that this new regulatory asset would be reflected in rate base in future rate proceedings. As indicated in the SOP, the potential rate base affect of these proposals were unacceptable to the Consumer Advocate.

See joint Application (Docket No. 05-0310), p. 12.

Absent Commission approval, the Companies would record a charge against AOCI in accordance with Statement of Financial Accounting Standards No. 87 ("FAS87"), *Employers' Accounting for Pensions* as part of recording a minimum pension liability. The Companies subsequently updated the requested accounting variance, via letter dated November 17, 2006, following the issuance of Statement of Financial Accounting Standards No. 158 ("FAS158"), *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

1 Q. IN YOUR OPINION, DOES THE CONSUMER ADVOCATE'S PROPOSED
2 PENSION TRACKING MECHANISM PROVIDE SUFFICIENT CERTAINTY
3 OF RECOVERY OF ANY REGULATORY ASSETS OR LIABILITIES THAT
4 HELCO MIGHT RECORD SO AS TO SATISFY THE PROVISIONS OF

5 FAS71?

6 A. Yes.

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9 ADVOCATE'S PROPOSED PENSION TRACKING MECHANISM WOULD
10 ALLOW HELCO TO RECORD A SEPARATE REGULATORY ASSET TO
11 OFFSET ANY CHARGE THAT WOULD OTHERWISE BE RECORDED
12 AGAINST EQUITY. ISN'T THIS TREATMENT CONTRARY TO THE
13 CONSUMER ADVOCATE'S POSITION IN DOCKET NO. 05-0310?

No. The application filed by the Companies in Docket No. 05-0310 did not represent a comprehensive remedy of the various regulatory and accounting challenges involving pension costs, unlike the Consumer Advocate's proposed pension tracking mechanism. It is true that the proposed pension tracking mechanism would allow the Company to establish a separate regulatory asset account to offset any charge against equity (e.g., AOCI) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan. However, contrary to the Companies' proposal in Docket No. 05-0310, the proposed

pension tracking mechanism specifically excludes any AOCI related regulatory asset from rate base, because such charges are not cash-affecting and the tracking mechanism is self-correcting in that it would allow the Company to recover any differences between the amount of FAS87 NPPC included in rates and the actual FAS87 NPPC recorded by the Company in future accounting periods.

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V. KEAHOLE CT-4 & CT-5 – AFUDC ADJUSTMENT.

9 Q. PLEASE DESCRIBE CA ADJUSTMENTS B-7 AND C-17.

This section of my direct testimony addresses the reasonableness of HELCO's proposed rate base inclusion of AFUDC capitalized to the recent additions at the Keahole Generating Station for purposes of quantifying overall revenue requirement. CA Adjustment B-7 (Exhibit CA-101) removes a portion of the Allowance for Funds Used During Construction ("AFUDC") from plant in service and quantifies the related impact on the accumulated depreciation reserve.²⁴ Since Keahole CT-4 and CT-5 were closed to plant in service in 2004, CA Adjustment C-17 (Exhibit CA-101) removes depreciation on the disallowed AFUDC from test year expense.

While this testimony section specifically addresses the Consumer Advocate's recommendation that a portion of the AFUDC associated with

Since the Keahole generating units and common facility investments were closed to plant in 2004, there should be a companion prorata adjustment to the test year balance of the accumulated deferred income tax reserve for the depreciation timing difference. Information was not readily available to quantify this impact at the time of the Consumer Advocate's filing.

Keahole CT-4/CT-5 and common facilities be excluded from the determination of rate base and from the computation of allowable depreciation expense, a separate testimony section will discuss additional adjustments proposed by the Consumer Advocate regarding Keahole costs, including noise abatement, landscaping, land rezoning and legal fees.²⁵

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7 Q. IS HELCO PROPOSING TO INCLUDE THE INSTALLED COST OF CONSTRUCTING KEAHOLE CT-4 AND CT-5 IN RATE BASE?

Yes. As indicated by HELCO T-15,²⁶ Keahole CT-4 became commercially available on May 25, 2004, followed by Keahole CT-5 on June 30, 2004. During those months, the majority of the recorded cost of construction, including AFUDC, associated with each unit and related common facilities were closed to plant in service. In the following months, certain additional construction costs were also closed to plant in service.²⁷

In determining average test year plant in service, HELCO's depreciable investment in the two generating unit additions at Keahole and related common facilities as of December 31st of 2005 and 2006 is summarized below:

²⁵ CA Adjustments B-8 and C-18 (Exhibit CA-101).

See page 2 of the direct testimony of HELCO witness Kenneth B. K. Fong, which has been designated as HELCO T-15.

HELCO response to CA-IR-191.

	12/31/05	12/31/06
Common Fac. (allowed D&O 18365)	\$7,570,152	\$7,570,152
Common Fac. (not related to existing gen.)	16,061,386	17,227,853
Keahole CT-4	54,292,035	53,595,766
Keahole CT-5	39,765,991_	38,448,278
Total (including AFUDC)	\$117,689,564	\$116,842,349

Source: HELCO responses to CA-IR-163 & CA-SIR-44.

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- 4 Q. IN THIS PROCEEDING, IS THE CONSUMER ADVOCATE CONTESTING
 5 HELCO'S DECISION TO ADD GENERATION IN WEST HAWAII OR ANY
 6 ASSERTED NEED TO ADD GENERATION CAPACITY IN ORDER TO
 7 MEET GROWING DEMAND FOR ELECTRICITY?
- 8 A. No. CA Adjustments B-7 and C-17 (Exhibit CA-101) merely seek to limit the amount of AFUDC that is recoverable from HELCO's ratepayers.

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A. KEAHOLE: PROJECT COST & SCHEDULE DURATION.

- 12 Q. PLEASE DESCRIBE THE CONSUMER ADVOCATE'S RECOMMENDED
 13 ADJUSTMENT TO DISALLOW A PORTION OF THE AFUDC CAPITALIZED
 14 BY HELCO IN THE COST OF KEAHOLE CT-4/CT-5 AND RELATED
 15 COMMON FACILITIES.
- A. After analyzing HELCO's AFUDC procedures and methods, preparing a model simulating the Company's accrual calculations, as well as considering project completion revisions and assessing the information HELCO "knew or should have known" when entering into the Keahole design, scheduling and planning processes, the Consumer Advocate recommends that the HPUC

disallow AFUDC in the approximate amounts of \$9.1 million (CT-4) and \$5.3 million (CT-5), including common facilities, from the plant investment HELCO proposes to include in rate base.

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- 5 Q. HOW MUCH OF THE COMPANY'S KEAHOLE PLANT INVESTMENT IS
 6 ASSOCIATED WITH AFUDC?
- A. In response to CA-IR-447, HELCO T-15 updated the capital cost for Keahole

 CT-4 and CT-5 to reflect actual costs through October 31, 2006, and revised

 the estimate of outstanding costs. It should be noted that the total project

 cost amount set forth in the following table is slightly different from the actual

 project costs HELCO supplied in response to CA-SIR-44.

	Amount	Percent
Expenditures, Permits & Fees	\$ 96,330,563	81.9%
AFUDC	21,283,972	18.1%
Total Project Costs – CT-4 & CT-5	\$ 117,614,535	100.0%

Source: HELCO T-15's response to CA-IR-447.

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Based on this information, HELCO has proposed to include about \$21 million of capitalized AFUDC in rate base, which represents approximately 18.1% of the cost of the units.

As will be discussed in greater detail herein, HELCO attempted to install CT-4 and CT-5 on an accelerated construction schedule at the Keahole site where it "knew or should have known" that achieving an accelerated schedule would be unlikely. Nevertheless, the construction of these generating units experienced substantial periods of project inactivity (i.e., the

absence of charges or material physical construction progress) due to the early purchase and receipt of major material components as well as the permitting difficulties. Although HELCO voluntarily stopped accruing AFUDC on both Keahole CT-4 and CT-5 effective December 1, 1998, the Company failed to temporarily cease AFUDC capitalization prior to that date, even during extended periods of limited progress.

The following table summarizes the Consumer Advocate's proposed adjustments on the actual AFUDC charged to each project, as of December 1998:

		Keahole CT-4	Keahole CT-5	Total	
Allowed AFUD		\$ 5,012,618	\$ 2,241,242	\$ 7,253,860	
12/98	AFODC	(14,099,896)	(7,561,191)	(21,661,087)	
Total		\$ (9,087,278)	\$ (5,319,949)	\$ (14,407,227)	

Sources: HELCO response to CA-IR-190 & CA workpapers supporting CA Adjustment B-7.

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12 Q. HOW HAVE THE LEVELS OF AFUDC AND NON-AFUDC COSTS

13 ASSOCIATED WITH KEAHOLE UNITS CT-4 AND CT-5 CHANGED OVER

14 TIME?

15 A. The forecast cost estimates for Keahole CT-4 and CT-5 increased
16 dramatically over time, including the amount of AFUDC, since the initial
17 construction planning stage. In my opinion, the actual level of AFUDC
18 HELCO proposes to include in plant in service is excessive. The following

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tables summarize the changes in the levels of construction expenditures and related AFUDC associated with the construction of these units.

		KEAHOL	E CT-4		
Year	Description	In-Service Date	Capital Expenditures	AFUDC	Total
	ESTIMATES:				
1991	CT-4 PUC Application **	Apr-94	\$30,759,800	\$2,883,500	\$33,643,300
1992	CT-4 Direct Testimony	Nov-94	34,615,600	3,606,000	38,221,600
1993	CT-5 Direct Testimony	Jul-95	32,797,800	4,167,900	36,965,700
1994	IRP Rebuttal Testimony	Jul-95	35,141,700	3,744,900	38,886,600
1996	Enserch Avoided Cost	Feb-97	35,137,300	8,529,700	43,667,000
1997	HCPC Avoided Cost	Dec-98	34,914,800	14,307,600	49,222,400
1998	HELCO Rate Case	Dec-98	34,919,300	14,217,700	49,137,000
1999	CA/HELCO-AIR-1	Jan-01	45,700,000	14,100,000	59,800,000
	ACTUAL:				
2006	HELCO Rate Case	May-04	55,625,844	11,882,235	67,508,079

^{**} The 1991 estimate was prepared for a site location other than Keahole.

Sources: HELCO response to CA/HELCO-AIR-1 (Docket No. 98-0013) & revised HELCO-1502 per HELCO T-15's response to CA-IR-447 (Docket No. 05-0315).

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Since the first Keahole site estimate in 1991, the estimated CT-4 capital expenditures (excluding AFUDC) remained relatively constant through HELCO's 1998 rate case forecast in the \$35 million range. However, the estimated AFUDC increased from a range of about \$4 million, during in the 1992-1994 period, to \$8.5 million in the 1996 avoided cost estimate (over two times the earlier estimates) and then to over \$14 million in subsequent estimates. After transfers and reallocations, the actual AFUDC for CT-4 is

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about \$11.9 million,²⁸ significantly higher than expected during the early fast-track construction years in the early 1990's.

		KEAHOI	LE CT-5		
Year	Description	In-Service Date	Capital Expenditures	AFUDC	Total
	ESTIMATES:				
1992	CT-4 Direct Testimony	Apr-96	\$26,443,600	\$1,783,400	\$28,227,000
1993	CT-5 Direct Testimony	Dec-94	23,107,800	1,776,300	24,884,100
1994	IRP Rebuttal Testimony	Oct-95	21,471,900	2,916,800	24,388,700
1996	Enserch Avoided Cost	Apr-97	21,481,800	5,437,400	26,919,200
1997	HCPC Avoided Cost	Dec-98	22,821,300	8,805,000	31,626,300
1998	HELCO Rate Case	Dec-98	23,042,000	8,855,000	31,897,000
1999	CA/HELCO-AIR-1	Mar-01	24,700,000	7,800,000	32,500,000
	ACTUAL:				
2006	HELCO Rate Case	Jun-04	40,704,720	9,401,737	50,106,456

Sources: HELCO response to CA/HELCO-AIR-2 (Docket No. 98-0013) & revised HELCO-1502 per HELCO T-15's response to CA-IR-447 (Docket No. 05-0315).

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Unlike CT-4, the estimated capital expenditures for CT-5 declined from the first Keahole site estimate of \$26.4 million to the \$21.5 million range, until increasing in forecasts subsequent to 1997 to the \$23-24.7 million range. Actual project capital expenditures are significantly higher at \$40.7 million. The initial CT-5 AFUDC estimates started at about \$1.8 million prior to 1994, increased to \$8.8 million in the 1997-1998 period and then decreased to \$7.8 million in 1999. The actual AFUDC for CT-5 is about \$9.4 million.²⁹ after

Revised HELCO-1502, p. 7, provided by HELCO T-15 in response to CA-IR-447.

²⁹ Revised HELCO-1502, p. 12, provided by HELCO T-15 in response to CA-IR-447.

transfers and reallocations, significantly higher than the early 1990's forecast estimates.

Α.

4 Q. WHAT ARE THE PRIMARY FACTORS CONTRIBUTING TO THE
5 SIGNIFICANT INCREASE IN THE AMOUNT OF AFUDC ASSOCIATED
6 WITH KEAHOLE CT-4 AND CT-5?

The total amount of AFUDC associated with any construction project is a function of the AFUDC rate, annual project expenditures and the overall duration of the project. For both Keahole units, "time" is the primary driver causing the dramatic increases in the CT-4/CT-5 AFUDC estimates from the early 1990's. Regarding CT-4, HELCO first began considering project expenditures as being subject to AFUDC capitalization in June 1991. Using this date as an approximation of the commencement of HELCO's planning commitment to this unit, each revision to HELCO's construction cost estimate, as set forth in the above table, generally encompassed further extensions in the estimated completion date. In the absence of a plan or intent to "stop" the continued capitalization of AFUDC, each extension resulted in a growing estimate of AFUDC to be capitalized on the project. Using June 1991 as a starting point, the following table summarizes the extension in the projected in-service date of CT-4, expressed in days and months:³⁰

For simplicity purposes, the above tables (both CT-4 & CT-5) assume that the in-service date was forecast for the first day of the calendar month. Obviously, if the forecast was premised on a mid-month or an end-of-month in-service date, the time lapse in both days and months would be increased accordingly.

KEAHOLE CT-4					
				Time	Lapse
Year	Description	Start of AFUDC	In-Service Date	Days	Months
	ESTIMATES:				
1991	CT-4 PUC Application (a)	6/1/91	4/1/94	1,035	34
1992	CT-4 Direct Testimony	6/1/91	11/1/94	1,249	41
1993	CT-5 Direct Testimony	6/1/91	7/1/95	1,491	49
1994	IRP Rebuttal Testimony	6/1/91	7/1/95	1,491	49
1996	Enserch Avoided Cost	6/1/91	2/1/97	2,072	68
1997	HCPC Avoided Cost	6/1/91	12/1/98	2,740	90
1998	HELCO Rate Case	6/1/91	12/1/98	2,740	90
1999	CA/HELCO-AIR-1	6/1/91	1/1/01	3,502	115
	ACTUAL:				
2006	HELCO Rate Case (b)	6/1/91	12/1/98	2,740	90
Note (a) Note (b)	The 1991 estimate was prepared Keahole CT-4 became commerc HELCO stopped accruing AFUDO not the 5/25/04 completion date.	ially available 5	5/25/04. 12/1/98	represents	the date that is to 12/1/98,
Source:	HELCO response to CA/HELCO- No. 05-0315).	AIR-1 (Docket I	No. 98-0013) & Hi	ELCO T-15,	p. 2 (Docket

Similar information for Keahole CT-5 is set forth below:

KEAHOLE CT-5					
				Time	Lapse
Year	Description	Start of AFUDC	In-Service Date	Days	Months
	ESTIMATES:				
1992	CT-4 Direct Testimony	7/1/93	4/1/96	1,005	33
1993	CT-5 PUC Application	7/1/93	12/1/94	518	17
1994	IRP Rebuttal Testimony	7/1/93	10/1/95	822	27
1996	Enserch Avoided Cost	7/1/93	4/1/97	1,370	45
1997	HCPC Avoided Cost	7/1/93	12/1/98	1,979	65
1998	HELCO Rate Case	7/1/93	12/1/98	1,979	65
1999	CA/HELCO-AIR-2	7/1/93	3/1/01	2,800	92
	ACTUAL:				
2006	HELCO Rate Case (a)	7/1/93	12/1/98	1,979	65
Note (a)	Keahole CT-5 became commerce HELCO stopped accruing AFUDO not the 6/30/04 completion date.				
Source:	HELCO response to CA/HELCO- No. 05-0315).	-AIR-2 (Docket N	No. 98-0013) & HE	ELCO T-15,	p. 2 (Docket

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In any event, the increase in actual AFUDC for both Keahole units is primarily associated with the length of construction duration (i.e., the time lapse between commencement of AFUDC in June 1991, or July 1993 for CT-5, and the changing in-service date estimates) and the escalating level of cumulative project expenditures. Using the first forecast project duration for Keahole CT-4, for illustration purposes, the project construction duration for AFUDC

capitalization purposes more than doubled (i.e., 90 months vs. 41 months).³¹ At the same time, construction expenditures increased 60% (i.e., \$55.6 million vs. \$34.6 million). The increase in project duration and capital expenditures directly contributed to the escalation in overall AFUDC from the \$3.6 million estimated in 1992 to the \$11.9 million actual AFUDC level.

With regard to Keahole CT-5, similar changes in project duration and capital expenditures also materially impact the increase in AFUDC. Since the 1992 estimate, the project duration increased from 33 months to 65 months, 32 while construction expenditures increased from \$26.4 million (estimate) to \$40.7 million (actual). As with CT-4, the increase in the CT-5 AFUDC forecast from \$1.8 million to \$9.4 million is primarily associated with the duration of the project in conjunction with higher capital expenditures.

Since the purpose of this discussion focuses on the primary factors driving AFUDC escalation, the "actual" construction duration of 90 months, as used above, was based on the 12/1/98 date that HELCO suspended the capitalization of AFUDC on Keahole CT-4, not the 5/25/04 date that the unit became commercially available. HELCO-1501, pp. 97-98, provides a Company estimate of \$39.7 million of additional AFUDC that would have been capitalized on these two Keahole units, had AFUDC not been voluntarily suspended on 12/1/98. However, the Consumer Advocate believes that the algorithms underlying Company's calculation of foregone AFUDC are incorrect (i.e., the amount should have been about \$52.6 million). Had the above discussion focused on the theoretical AFUDC that would have been capitalized through May 2004, the discussion would have reflected a construction duration of 156 months.

The 65-month schedule duration is based on the 12/1/98 date HELCO ceased capitalizing AFUDC. The actual project duration, through June 2004, would be 132 months.

1	Q.	YOU PREVIOUSLY INDICATED THAT KEAHOLE CT-4 AND CT-5 BECAME
2		COMMERCIALLY AVAILABLE IN MAY AND JUNE 2004, RESPECTIVELY.
3		WHY IS IT NOW APPROPRIATE TO ADDRESS THE REASONABLENESS
4		OF AFUDC OR OTHER COSTS CHARGED TO THESE PROJECTS?
5	A.	The reasonableness of the cost of any capital project is typically not
6		addressed by regulatory agencies until at least the first rate proceeding in
7		which the utility seeks to include said costs in the determination of its overall
8		revenue requirement.33 For HELCO and Keahole CT-4/CT-5, the pending
9		rate case is the appropriate time to address such matters.
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11	Q.	IS THIS RATE CASE THE FIRST PROCEEDING IN WHICH THE
12		CONSUMER ADVOCATE HAS INFORMED THE COMMISSION OF ITS
13		CONCERN WITH THE LEVEL OF AFUDC HELCO HAS CAPITALIZED AS
14		PART OF THE COST OF THESE TWO GENERATING UNITS?
15	A.	No. While this subject has not been exhaustively researched, I am aware of
16		several prior proceedings in which the Consumer Advocate has expressed
17		concern with the cost of these projects, including AFUDC.
18		In its Statement of Position in Docket No. 98-0013 (page 42), the
19		Consumer Advocate discussed the need to determine the reasonableness of

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At page 17 of Decision and Order No. 14284 (Docket No. 7623), the Commission found that "the prudence of the expenditures made by HELCO in acquiring CT-5 without prior commission approval, assuming that HELCO's own generating facility is used and useful for utility purposes, shall be decided in HELCO's rate case following the installation of HELCO's facility."

the AFUDC included in the cost of the Keahole projects if the pricing of the then pending Encogen PPA was to be evaluated using Keahole as a measure of avoided costs. In other words, the Consumer Advocate contended that if the Keahole projects included costs deemed to be unreasonable or inappropriate for cost recovery from HELCO's ratepayers, then such costs should also be removed from HELCO's avoided costs calculation to ensure that PPA pricing does not effectively encompass said costs.³⁴

In Docket No. 7623, the Consumer Advocate also raised concerns regarding the reasonableness of the level of AFUDC accrued on the Keahole project expenditures.³⁵

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B. KEAHOLE: AFUDC ADJUSTMENT QUANTIFICATION.

- 13 Q. HAVE YOU REVIEWED HELCO'S CAPITALIZATION OF AFUDC ON
 14 ACTUAL KEAHOLE CT-4 AND CT-5 CONSTRUCTION EXPENDITURES?
- 15 A. Yes. HELCO provided monthly data regarding its actual project expenditures, 16 capitalized AFUDC and AFUDC rates in response to CA-IR-190. Using this 17 data, several distinct, but related, analyses were prepared. First, an AFUDC

In Decision and Order No. 16948 (Docket No. 98-0013), the HPUC concluded that consideration of AFUDC amounts other than those used by HELCO and Encogen were beyond the scope of the issues identified in Prehearing Order No. 16800 and granted HELCO's motion to strike pertinent portions of the direct testimonies and exhibits filed by the Consumer Advocate on such issue, thereby declining to reconsider the issue in Docket No. 98-0013.

Consumer Advocate's Opening Brief, Docket No. 7623, p. 26; Consumer Advocate's Statement of Position, Docket No. 98-0013, pp. 42-45.

simulation model was developed in order to evaluate and test the methodology employed by HELCO to capitalize AFUDC on the two new Keahole units from project inception through December 1998.³⁶

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Second, using this data set, two graphs (see Exhibit CA-307) were prepared to depict the actual recorded costs of Keahole CT-4 and CT-5, including and excluding AFUDC, from the commencement of project charges through November 1998, since HELCO stopped AFUDC on December 1. These graphs serve as visual aids for purposes of evaluating trends in recorded costs and assessing the impact of capitalized AFUDC thereon.

Third, these individual graphs, a combined graph for both units (see Exhibit CA-308) and other data provided by the Company (e.g., various discovery responses, HELCO-1501, etc.) were used to identify extended periods of construction inactivity, such as identified work stoppages and periods of limited change in cumulative construction expenditures (excluding AFUDC) on each Keahole unit while the cumulative total balance (including AFUDC) continued to increase.

Finally, using the base line established by the AFUDC simulation model, it was possible to halt the capitalization of AFUDC during the identified work stoppages and periods of limited construction activity. The Consumer

HELCO suspended AFUDC capitalization on Keahole CT-4 and CT-5 effective December 1, 1998.

Advocate's proposed AFUDC adjustment was quantified by comparing the resulting AFUDC with the AFUDC from the base line simulation model.

Α.

4 Q. PLEASE DESCRIBE THE REFERENCED GRAPHS.

Exhibits CA-307 (separate graphs for Keahole CT-4 & CT-5) and CA-308 (Keahole CT-4/CT-5 combined) show HELCO's cumulative monthly expenditures (including and excluding AFUDC), beginning with the date that HELCO commenced accumulating project costs and continuing through December 1998 (CT-4 and CT-5 individually) and through December, 2004 (CT-4 and CT-5 combined). Even though the combined graph contains cumulative project cost data for calendar years 1999-2004, it should be noted that HELCO stopped capitalizing AFUDC on December 1, 1998. The effect of such "stoppage" is that the spread or difference between the two graph lines (i.e., including and excluding AFUDC) remains constant or run in parallel beginning in December 1998.

In order to provide additional project time line perspective to the cumulative cost curves on Exhibit CA-308 (combined), dialogue boxes have been inserted with arrows pointing to the chronological location of various identified "events" on the project expenditure curve. For example, dialogue boxes identify when HELCO ordered the combustion turbine for CT-4 (October 1991), when the Commission approved HELCO's application to commit funds to CT-4 (January 1994), and when that combustion turbine was received (February 1994) by the Company. Similarly, the initial forecasted

in-service date for the units (i.e., corresponding with the Keahole site) is also identified, as is the month HELCO commenced with Pre-PSD construction (August 1997).

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A.

Q. WHAT DO YOU BELIEVE THESE GRAPHS SHOW?

There are several important factors highlighted by these graphs. First, HELCO was quick to place an order for the combustion turbines in October 1991, although delivery did not occur until 32 months later in February 1994 - one month after the Commission approved its request for authority to commit funds to construct CT-4. By comparison, the 1992 forecast was based on an in-service date of November 1994.

Second, although HELCO commenced AFUDC accounting for CT-4 in June 1991, the Company recorded relatively minimal monthly, non-AFUDC charges on the project through September 1992 (about 15 months) when the cumulative balance first exceeded \$1 million (excluding AFUDC). At that point, HELCO was already 15 months into the 41-month construction time line forecast in 1992. In October 1992, HELCO made its first payment to Stewart and Stevenson Services, Inc. for the combustion turbines.³⁷ Shortly thereafter, HELCO began incurring additional costs, which dramatically increased its expenditures on CT-4 to slightly in excess of \$15 million (excluding AFUDC) over the following 18 months (i.e., by March 1994). By

³⁷ HELCO response to CA/HELCO-AIR-20, Docket No. 98-0013.

the original November 1994 in-service date, the cumulative expenditures were approaching \$19 million (excluding AFUDC), but the in-service date had been moved to July 1995 during 1993.

Third, by January 1995, the cumulative CT-4 expenditures first exceeded \$20 million (excluding AFUDC) and the Company had already taken delivery of a number of its major components (e.g., combustion turbines, wastewater treatment and demineralizer equipment, control system, pumps, oil water separator, control panels, etc.). However, by the time that the avoided cost forecast was assembled in 1996, the in-service date for CT-4 had been further delayed to February 1997.

Fourth, the CT-4 project again went to "sleep" (i.e., limited additional expenditures were charged to the project) throughout calendar years 1995, 1996 and 1997. It was not until three years later, January 1998, that the cumulative expenditures exceeded \$23 million, following commencement of pre-PSD construction in August 1997. During 1997, HELCO again slipped the CT-4 in-service date to December 1998.

Fifth, except for the premature receipt of the required materials to construct the unit, no substantial physical construction progress was made until the issuance of the pre-PSD construction permit. However, by October 1997, HELCO had already charged approximately \$9.7 million of AFUDC alone to the Keahole CT-4 project. Following receipt of the pre-PSD permit, HELCO charged an additional \$4.4 million (\$14.1 million minus \$9.7 million) of AFUDC and \$13.4 million (\$35.7 million minus \$22.2 million) of

construction expenditures to the project during the remainder of 1997 and 1998.³⁸ For additional perspective, the \$4.4 million of AFUDC recorded subsequent to the issuance of the pre-PSD permit and November 1998 exceeded the total AFUDC forecasted for the entire CT-4 project, as recently as 1994. The "next" forecast in 1996 slipped the in-service date to February 1997 and increased AFUDC to approximately \$8.5 million.³⁹

Although not separately noted on Exhibit CA-307, HELCO stopped accruing AFUDC on both Keahole CT-4 and CT-5 effective December 1, 1998. According to page 7 of revised HELCO-1502,⁴⁰ the Company's most current cost estimate for Keahole CT-4, corresponding with the May 2004 commercial date, has a total project cost of \$67.5 million (\$55.6 million construction expenditures plus \$11.9 million AFUDC).

In summary, these graphs illustrate that Keahole CT-4 appears to have experienced substantial periods of project inactivity (i.e., the absence of charges to or progress on physical project construction) due to the early purchase and receipt of major material components as well as the permitting difficulties experienced with the Keahole generation site.

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³⁸ HELCO response to CA-IR-190.

³⁹ CA/HELCO-AIR-1, Docket No. 98-0013.

⁴⁰ Revised HELCO-1502 provided by HELCO T-15 in response to CA-IR-447.

1 Q. REFERRING TO EXHIBIT CA-307, WOULD A SIMILAR DISCUSSION
2 APPLY TO THE KEAHOLE CT-5 GRAPH?

Yes, in general terms. However, because Keahole CT-4 is the first of two generating units recently added at that site, 41 the time line and milestones are distinctly different for Keahole CT-5. For example, the construction accounting and AFUDC process for CT-5 started in July 1993, rather than the June 1991 date for CT-4. In addition, the cumulative project expenditures (excluding AFUDC) increase from \$5.4 million in July 1993 to about \$10 million (excluding AFUDC) by March 1994. As of November 2003, the cumulative CT-5 project expenditures more than tripled to in excess of \$30 million, but CT-5 also appears to have experienced substantial periods of relative project inactivity during the intervening 9.5 years. However, unlike Keahole CT-4, the Consumer Advocate is unable to locate any Commission decision, particularly in Docket No. 7623, specifically authorizing HELCO to commit funds to Keahole CT-5.

Α.

The Keahole Generating Station has been in operation since 1973. At the present time, there are three combustion turbines at Keahole (CT-2, CT-4 and CT-5) plus three diesel engines with a combined generating capacity of about 65 MWs. [HELCO-1501, p.3] Keahole CT-4 and CT-5 represent about 44.3 MWs of capacity. [HELCO-502.]

1 Q. PLEASE EXPLAIN HOW YOU QUANTIFIED THE PORTION OF THE
2 AFUDC CHARGED TO EACH PROJECT THAT THE CONSUMER
3 ADVOCATE RECOMMENDS BE DISALLOWED.

Α.

Although a subsequent testimony subsection addresses what HELCO knew or should have known during the 1988-1991 time period, there should have been early concerns with the selection of the Keahole site for new generation, including likely challenges in securing necessary permits and community opposition. HELCO-1501 (pages 55-68) discusses in detail the various delays in obtaining land use approval, air and construction permits, and authorization to commence construction.

Using the AFUDC simulation model discussed previously, it was possible to quantify the Consumer Advocate's AFUDC adjustment recommendation by stopping the accrual of AFUDC on CT-4 and CT-5 during the long periods in which it appears that limited, if any, progressive construction activity was authorized on the projects. HELCO should have realized, by September 1994, that the opportunity to obtain the necessary permitting approvals for CT-4 and CT-5 on an expedited basis was remote, given the growing opposition to the expansion at Keahole. While HELCO was first authorized to commence pre-PSD construction in August 1997, all pre-PSD construction was later halted in September 1998 and not restarted until January 1999 – after HELCO finally stopped capitalizing AFUDC in December 1998.

For Keahole CT-4 and CT-5, the accrual of AFUDC was suspended in the AFUDC simulation model during the period prior to receiving Commission approval in January 1994 and between October 1994 through July 1997. The amount of cumulative AFUDC resulting from this simulation through December 1998 was then compared to the actual amount of AFUDC recorded as of December 1998, with the resulting difference representing the value of the Consumer Advocate's recommended disallowance.

Α.

Q. COULD YOU BRIEFLY OUTLINE THE DELAYS HELCO EXPERIENCED IN OBTAINING THE LAND USE APPROVAL, AIR AND CONSTRUCTION PERMITS REQUIRED TO CONSTRUCT KEAHOLE CT-4 AND CT-5?

Yes. 42 In August 1992, HELCO filed its application for an amendment to the Keahole Conservation District Use permit (referenced in HELCO-1501 as "CDUA" and occasionally as "CDUP"), originally issued in 1973 and subsequently amended, with the Hawaii Board of Land and Natural Resources ("BLNR") seeking land use approval for the planned generation expansion. The filing of this application also triggered the need for an Environmental Impact Statement ("EIS"), which was submitted in draft form in late 1992. At a BLNR public hearing held in January 1993, a number of project opponents testified against the application and requested a contested case hearing. After a series of delays and complications, HELCO obtained a

HELCO-1501 was the primary source for the following discussion.

"default entitlement" in 1996, in lieu of an approved permit. However, the default entitlement led to additional legal challenges and administrative proceedings as a result of opposition to the project. In January 1997, the Third Circuit Court issued a decision allowing HELCO to put its land to use as specified in the application, which it affirmed and clarified in July 1997. At that time, HELCO could seek grading and building permits from the County of Hawaii for pre-PSD construction, which commenced in August 1997. The default entitlement was not resolved until 2003, with the Supreme Court's affirmation of a lower court judgment and a negotiated settlement, resolving other litigation and disputes.⁴³

In 1992, HELCO retained the services of an outside consultant to prepare an air permit application for the Keahole project. In January 1993, HELCO filed the application with the Hawaii Department of Health ("DOH") for approval of a Prevention of Significant Deterioration ("PSD")/ Covered Source air permit, which was also subject to review by the U.S. Environmental Protection Agency ("EPA"). In November 1993, DOH promulgated new Covered Source Permitting rules, resulting in HELCO resubmitting its Keahole air permit application in February 1994. Five public hearings followed in September 1994, April 1995, March 1997, October 1999 and

March 2001. After several challenges, the Keahole air permit was deemed effective in November 2001.⁴⁴

Because Pre-PSD construction work could not commence until August 1997, the CT-4 and CT-5 projects reflected little, if any, planned physical construction activity prior to that date. However, according to the response to CA-IR-507, HELCO did not begin pre-PSD construction until October 7, 1997. Following additional legal activity and inquiries by DOH and EPA, HELCO voluntarily ceased work on certain pre-PSD construction items on July 6, 1998. On September 14, 1998, HELCO immediately halted all work upon receipt of a Notice of Violation ("NOV") from the EPA for pre-PSD construction. Construction restarted on certain pre-PSD items with EPA approval in January 1999. However, on October 28, 2000, pre-PSD construction was stopped following a finding by the Circuit Court that HELCO's three-year construction deadline expired in April 1999. HELCO did not resume construction until April 30, 2002, when the Circuit Court lifted a stay on construction due to BLNR granting an extension in the construction schedule. But, HELCO again stopped construction on September 28, 2002 as a result of the Circuit Court reversing BLNR's extension. HELCO later resumed construction activity in November 2003, after the Circuit Court vacated its earlier decision reversing BLNR's construction extension.⁴⁵

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⁴⁴ HELCO-1501, pp. 55-63.

HELCO response to CA-IR-507.

1 Q. YOU EARLIER INDICATED THAT HELCO SHOULD HAVE KNOWN BY
2 SEPTEMBER 1994 THAT THE OPPORTUNITY TO OBTAIN THE
3 NECESSARY PERMITTING APPROVALS FOR CT-4 AND CT-5 ON AN
4 EXPEDITED BASIS WAS REMOTE. WHAT IS THE BASIS FOR THAT
5 STATEMENT?
6 A. In September 1994, DOH held public hearings regarding the air permit for the

In September 1994, DOH held public hearings regarding the air permit for the Keahole CT-4, CT-5 and ST-7 projects. At about this same time, HELCO submitted a request to modify the air permit for the Keahole CT-2 unit, using more current meteorological data than was presented in the application for the planned generation additions. Because of the availability of more recent data, DOH concluded that a second public hearing was necessary.⁴⁶

In May 1994, HELCO appeared before BLNR regarding its CDUA application, without a contested case hearing being held. Although BLNR was unable to cast enough votes to approve or deny the application, HELCO obtained a "default entitlement" by operation of law, due to the statutory time limit in the CDUA having expired a few days after the hearing. However, HELCO was unable to commence construction because the air permit had not yet been granted. Project opponents challenged the "default entitlement," with the Third Circuit Court granting a stay on HELCO's ability to proceed with construction. In November 1994 in response to the default entitlement challenge, the Circuit Court remanded HELCO's CDUA application back to

⁴⁶ HELCO-1501, pp. 59-60.

DLNR for a contested case hearing. Although the combustion turbines and other major equipment had already been delivered and placed in storage, HELCO's ability to initiate pre-PSD related construction was delayed pending the contested case hearing.⁴⁷

In August 1994, the Consumer Advocate filed its opening brief in Docket No. 7623, regarding HELCO's application for approval to commit funds for the construction and installation of Keahole CT-5 and ST-7. At page 4, the Consumer Advocate expressed its own concerns regarding the future of the Keahole expansion:

There is, however, another consideration that is cause for more immediate concern and which may have a direct bearing on the availability of alternatives to CT-5 and ST-7. In light of the problems that HELCO has encountered with regard to the common permits for CT-4, CT-5 and ST-7, it has become doubtful that CT-4 will actually be provisioned in 1995. In fact, there is serious question as to whether CT-4, CT-5 or ST-7 will ever be provisioned at Keahole.

[Consumer Advocate's Opening Brief, Docket No. 7623, p. 4]

Consequently, significant facts were known in the September 1994 time frame that consistently signaled further delays in the permitting and construction schedule. At that time, HELCO knew or should have known that limited physical construction would be allowed for a potentially protracted period, which should have reasonably resulted in a decision to suspend AFUDC capitalization until the necessary permits were received allowing

construction to proceed on a reasonably planned and progressive schedule of activities.

Basically, the Consumer Advocate's recommendation quantifies the amount of AFUDC to be disallowed by "stopping" the accrual of AFUDC in October 1994 and not restarting the accrual until August 1997. By using the simulation model to quantify the effect of such stoppage, the excess AFUDC amounts eliminated from rate base are premised on HELCO's actual cumulative construction expenditures and actual AFUDC rates on a monthly basis.

Α.

11 Q. YOU PREVIOUSLY STATED THAT HELCO CEASED ACCRUING AFUDC

12 ON KEAHOLE CT-4 AND CT-5 EFFECTIVE DECEMBER 1, 1998. HAVE

13 YOU REVIEWED ANY INFORMATION EXPLAINING THE BASIS FOR

14 SUCH ACTION?

Yes. I have reviewed two sources of information, which explain the Company's rationale for suspending AFUDC effective December 1, 1998. In Docket No. 98-0013, HELCO provided the following response to CA/HELCO-AIR-35:

Note that HELCO decided to discontinue the accrual of AFUDC on CT-4 and CT-5 effective December 1, 1998. Although management believes it has acted prudently with respect to this project and that the generating unit delays are being imposed on HELCO by external forces, are unavoidable and are beyond HELCO's control, the length of the delays to date and potential further delays were factors considered by management in the decision to discontinue the accrual of AFUDC.

[CA/HELCO-AIR-35, Docket No. 98-0013]

In the current docket, HELCO-1501 represents HELCO's Keahole Cost
Report filed with the Commission on September 7, 2005. This Cost Report
provides a detailed description of the history of the expansion of generation at
the Keahole Generating Station, including the following discussion of the
Company's decision to terminate AFUDC on CT-4 and CT-5:

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The CT-4 and CT-5 projects were subject to delays caused by external factors, which were beyond the control of the Company, including the process of obtaining permits from governmental authorities, and unforeseen litigation. Under HELCO's policy, AFUDC was applied to the project, and continued to be applied during the project delays caused by external factors. However, as a result of Environmental Appeals Board ("EAB") decision (see discussion of EAB decision in Appendix C) on November 25, 1998, HELCO realized there would be further, substantial delays in HELCO's construction of CT-4 and CT-5. At that point, while HELCO management had acted prudently with respect to the Keahole project, a decision was made to stop the accrual of AFUDC effective December 1, 1998. The length of delays to date at that time and uncertainty over potential future delays to meet EAB's remand requirements, including another round of public comments, were factors considered in the decision to stop the AFUDC accrual. [HELCO-1501, p. 96]

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Q. SO, DOES HELCO CONCUR WITH YOUR VIEW THAT THESE PROJECTS
 EXPERIENCED EXTENDED PERIODS OF CONSTRUCTION INACTIVITY
 AND THAT AFUDC SHOULD HAVE BEEN STOPPED BEFORE
 DECEMBER 1998?
 A. No. It is clear that HELCO does not concur with my view of the construction
 activity and proposed suspension of AFUDC on these projects. In likely

anticipation of possible challenges to the amount of AFUDC capitalized on

these Keahole projects, the following discussion appears at pages 95-96 of

HELCO-1501:

HELCO's policy is to apply AFUDC to projects when construction expenditures for a project begin on a "planned progressive basis". The application of AFUDC generally begins after a project is formally approved by HELCO's management, and engineering charges are recorded against the project and classified as construction work in progress ("CWIP"). After the initial application, AFUDC is applied every month until the project is completed, or until the project is delayed at management's discretion or canceled or abandoned. . . . In the case of a project delayed at management's discretion, AFUDC is stopped at the point of delay, and is resumed when the project is reactivated. The application of AFUDC is continued if a project delay is caused by external factors.

If the project delay is caused by external factors and events beyond management's control, continuing to calculate and capitalize AFUDC is appropriate. In this situation, the Company is actively pursuing construction of the project, and is doing its best to proceed with, and complete, the project on a planned progressive basis. "Planned progressive basis" means proceeding without delay, except for the delays that are inherent in the asset acquisition process, such as the ordering, purchasing and delivery of long lead time material, and delays due to permitting and external approval processes. As such, the related financing costs should be treated as asset acquisition costs and capitalized.

From a regulatory perspective, investors expect a reasonable rate of return on their funds used for HELCO's capital construction program. The return is provided through the rate of return on rate base for completed projects, and through the addition of AFUDC to the cost of projects currently being constructed. If the Company is not allowed to apply AFUDC during periods of project delays caused by external factors, and the investment is not allowed in the rate base as construction work in progress, then there is no way, currently, for investors to earn a return on their investment. This would not be fair to investors in the case where the project delays are caused by external factors, which are beyond the Company's control.

The CT-4 and CT-5 projects were subject to delays caused by external factors, which were beyond the control of the Company, including the process of obtaining permits from governmental authorities, and unforeseen litigation. HELCO's policy, AFUDC was applied to the project, and continued to be applied during the project delays caused by external factors. However, as a result of Environmental Appeals Board ("EAB") decision (see discussion of EAB decision in Appendix C) on November 25, 1998, HELCO realized there would be further, substantial delays in HELCO's construction of CT-4 and CT-5. At that point, while HELCO management had acted prudently with respect to the Keahole project, a decision was made to stop the accrual of AFUDC effective December 1, 1998. The length of delays to date at that time and uncertainty potential future delays to meet EAB's requirements, including another round of public comments, were factors considered in the decision to stop the AFUDC accrual. [HELCO-1501, pp. 95-96]

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I certainly understand HELCO's position on this point. While the magnitude of the delays experienced might have been unexpected, the Company knew or should have known that it would face significant challenges when it made the decision to locate the new generation at Keahole – both in obtaining permit approvals and from community opposition.

In addition, the above discussion only addresses what is considered fair and reasonable from the perspective of HELCO's investors. There is no discussion of reasonableness or fairness from the perspective of the Company's ratepayers, from whom HELCO is seeking to recover this excessive AFUDC. As indicated in an earlier table, total AFUDC on these two projects has increased from the \$6 million to \$7 million range, during the 1993-1994, to \$21 million.

Finally, HELCO maintains its books and records in conformance with the National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts ("USOA"), unlike mainland utilities who typically employ a USOA promulgated by the Federal Energy Regulatory Commission. However, over the years, NARUC has published a series of interpretations of its USOA for Electric and Gas Utilities. NARUC Interpretation No. 83 specifically discusses the period of capitalization of AFUDC, which states:

Question:

What is the proper period for capitalization of allowance for funds used during construction?

Answer:

Allowance for funds used during construction (AFUDC) may be capitalized starting from the date that construction costs are continuously incurred on a planned progressive basis. Interest should not be accrued for the period prior to: (1) the date of issuance of the preliminary permit by the Commission of a licensed hydroelectric project; and (2) the date of the application to the Commission for a certificate to construct facilities by a natural gas company. AFUDC maybe allowed by the Commission for the period prior to the above dates if so justified by the company. No AFUDC interest should be accrued during period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances. . . .

In light of the fact that a formal approval process exists for capital improvement projects in the State of Hawaii, one could reasonably argue that Hawaii utilities should <u>not</u> capitalize any AFUDC on project expenditures before receiving Commission approval. In addition, NARUC Interpretation No. 83 also indicates that no AFUDC should be accrued during periods of interrupted construction, unless the utility can justify the interruption as

reasonable under the circumstances. This Interpretation squarely rejects capitalization, when construction is interrupted, and would require the utility to seek regulatory authority to do otherwise. To my knowledge, HELCO has not heretofore sought such approval from this Commission.

In my opinion, the Commission must address the question of whether HELCO bears any culpability for attempting to expedite generation expansion plans in the face of known opposition or whether HELCO was blind-sided by unknown developments and events. I believe that HELCO should be held accountable for attempting to fast track these projects, in the face of known opposition, and that HELCO should have sought to minimize its expenditures until such time as the necessary permits were reasonably certain.

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Q. AT PAGE 96 OF HELCO-1501, HELCO CONTENDS THAT SHAREHOLDERS HAVE ALREADY BORNE SIGNIFICANT COST RESPONSIBILITY, AS A RESULT OF THE DECISION TO STOP AFUDC ON DECEMBER 1, 1998, IMPLYING THAT IT WOULD BE UNFAIR TO DENY ANY OF THE AFUDC ACTUALLY CHARGED TO KEAHOLE CT-4 AND CT-5. DO YOU CARE TO COMMENT?

A. Yes. HELCO should be commended for finally stopping the capitalization of AFUDC in December 1998, otherwise the amount of AFUDC at issue in the current case would be significantly higher than it is now. Nevertheless, I believe that HELCO should have similarly suspended AFUDC during the earlier protracted period during which physical construction was suspended.

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At page 96 of HELCO-1501, the Company indicates that an additional \$39.7 million of AFUDC would have been charged to the projects, absent the suspension, which HELCO contends to represent costs already borne by shareholders. There are several points that merit comment. First, I believe that the \$39.7 million amount is in error. In early February 2007, I had occasion to review the spreadsheet file supporting the calculation of this amount and the AFUDC simulation presented in HELCO-1501, pages 97-98. Had the spreadsheet properly compounded AFUDC, similar to what is done in actual practice, HELCO would have calculated "foregone" AFUDC of about \$52.6 million, not \$39.7 million. It should be clearly noted that this does not represent total project AFUDC, but unrecorded AFUDC from November 1998 through project completion. In fact, the \$52.6 million of AFUDC alone is just shy of the \$56.6 million capital expenditures (i.e., without AFUDC) HELCO had estimated as the total cost of the CT-4 and CT-5 project in 1994.

Second, the amount of AFUDC for a given month is a function of the AFUDC rate and the cumulative balance to which the rate is applied. As a consequence, the amount of monthly AFUDC at the end of a major construction project will be significantly higher than in earlier months of the construction cycle. So, the monthly amount of post-November 1998 AFUDC will be materially higher than earlier months. However, most of the additional AFUDC, regardless whether the \$39.7 million or \$52.6 million is considered, is related to calendar months in which HELCO did not have permitting approval to enable the Company to proceed with construction. If AFUDC

continued to be suspended until construction resumed in November 2003 and terminated when the units were completed and placed in service, shareholders would have only forgone about \$4.2 million of AFUDC by not restarting AFUDC. In contrast, HELCO is requesting that ratepayers bear about \$21 million of actual AFUDC, while the Consumer Advocate recommends that only \$7.3 million should be recoverable from ratepayers.

Finally, for purposes of this case, I do not take issue with the conceptual framework as to when the capitalization of AFUDC should commence, be suspended or terminated, but rather with how that framework was applied to these specific projects. Assuming HELCO management reasonably believed that a 41-month construction cycle for CT-4 was achievable (when the forecast was prepared in 1992) or in 49 months (in 1994), AFUDC should have commenced following Commission approval of the commitment of funds for the project and commencement of project charges. However, significant questions exist as to whether such construction duration targets were realistic in light of then known opposition. I strongly disagree with HELCO's implication that construction on Keahole CT-4 and CT-5 continued without significant interruption.

As discussed separately herein, HELCO "knew or should have known" very early in the project time line that the permitting process would be a substantial obstacle to the timely and cost effective construction of CT-4 and CT-5 at the Keahole site. Once HELCO assumed the risk of potentially protracted delays in the permitting process, this Commission should <u>not</u>

accept the argument that the substantial escalation in AFUDC is at all reasonable under the circumstances. In light of the inherent risks undertaken by HELCO in its decision to construct CT-4 and CT-5 at Keahole on an overly optimistic construction schedule, the Company's ratepayers should not be burdened with the resulting excessive costs through inclusion in HELCO's rate base.

Q.

Α.

C. KEAHOLE: OVERVIEW OF THE AFUDC PROCESS.

WHAT IS THE FUNCTION AND PURPOSE OF AFUDC?

The capitalization of AFUDC provides a mechanism through which the utility is allowed to recover project related financing costs from the generation of customers who actually benefit from assets that are used and useful in providing utility service.

When a utility expends funds for a capital or construction project, the company incurs certain financial costs in the form of additional debt interest and/or foregone opportunities related to equity funds. Regulatory agencies have historically considered two different options for purposes of compensating utilities for such construction-related financial costs. Under certain circumstances, some regulatory agencies have allowed the utility to include construction work in progress ("CWIP") in rate base for purposes of

determining revenue requirement.⁴⁸ The more common regulatory approach is to allow the utility to capitalize AFUDC as part of the project investment (i.e., original cost). AFUDC is designed to allow the capitalization of the cost for the period of borrowed funds used for construction purposes and a reasonable rate on other funds (i.e., preferred and common equity) when so used.

AFUDC is considered to be a non-cash return at the time such funds are charged to the construction project, as "cash" does not concurrently change hands between the company and its customers. Once the construction project is completed and placed in service, AFUDC does generate cash revenue for the utility through the inclusion of the completed project investment (including AFUDC) in the plant in service component of rate base, on which a return on and a return of (i.e., depreciation expense) that investment is allowed for ratemaking purposes.

Since AFUDC increases the utility's plant investment, the company recovers the capitalized AFUDC over the life of the asset through depreciation expense and earns a return on the net undepreciated (or unrecovered) balance of AFUDC. However, during the construction phase when AFUDC is being accumulated within the construction project work order, there is no cash exchange between the company and its customers.

The inclusion of CWIP in rate base allows the utility earns a "current" return on its construction expenditures, even though the subject utility project is neither used nor useful in providing utility service. Whenever CWIP is included in rate base, no AFUDC is allowed to be capitalized on construction projects.

1 Q. WHAT ARE THE PRIMARY FACTORS THAT DRIVE THE AMOUNT OF
2 AFUDC CAPITALIZED ON A PARTICULAR CONSTRUCTION PROJECT?

Α.

There are three primary factors which determine the amount of AFUDC includable in the cost of a particular project: the amount and timing of project expenditures; the cost rate used for AFUDC purposes; and the duration of the construction project.

Since AFUDC is computed on a monthly basis, the amount of the monthly project expenditures and the timing of the expenditures over the project's duration directly affect the total amount of capitalized AFUDC. In a particular construction schedule, the utility has a certain degree of latitude in deciding when to purchase the raw materials or the components required for the project, depending on whether the construction project is being fast-tracked (i.e., constructed on an accelerated schedule) and the ordering, or manufacturing, lead-time required by the selected vendors. Because AFUDC is computed monthly, utility decisions to expend funds earlier, rather than later, in the construction cycle will increase the AFUDC base, as well as the number of months such expenditures are subject to AFUDC, thereby increasing the overall level of AFUDC charged to the project, all else remaining constant.

Typically, most energy utilities quantify the AFUDC cost rate consistent with the methodology prescribed by the Federal Energy Regulatory

Commission ("FERC"). HELCO is no exception. Basically, the FERC method requires that short-term debt ("STD") be considered as the first source of financing a company's investment in CWIP, with any CWIP in excess of STD assumed to be financed pro rata by the weighted cost of long term debt, preferred equity and common equity. The weighted cost of the debt and preferred equity components are periodically recomputed, as new issues, recalls or refinancings occur. However, the cost of common equity is set at the return on equity adopted by the regulatory body having primary rate jurisdiction over the company's operations.

When a utility commences the planning and evaluation of one or more construction projects, the duration of each project from the planning stage through project completion must be considered. Both the overall duration of the project and the timing of construction expenditures will directly influence the overall level of AFUDC charged to the project. A combination of the targeted completion date, construction schedule sequence (i.e., critical path) and the component ordering lead time should be carefully considered when entering into purchase commitments with suppliers and/or construction contractors. If funds are committed too far in advance of the need for the

See CA/HELCO-AIR-25 (Docket No. 98-0013).

A variation from the assumption that STD serves as bridge, or the first source of, financing arises when the capital structure employed for ratemaking purposes includes STD as a source of financing rate base, as has been the past practice of the HPUC. In such circumstances, the AFUDC rate is more appropriately based on the weighted average cost of debt (both short term and long term), preferred equity and common equity.

1 construction materials or the project schedule becomes unreasonably 2 protracted, excessive AFUDC could be charged to the project. 3 ONCE AFUDC IS CHARGED TO A PARTICULAR CONSTRUCTION 4 Q. PROJECT, DOES THAT SIMPLE FACT ENSURE SUCH AMOUNTS ARE 5 6 **ULTIMATELY RECOVERABLE FROM RATEPAYERS?** 7 No. The mere act of "recording" AFUDC does not guarantee the recovery of Α. 8 such amounts from ratepayers. Regulatory bodies, such as this Commission, 9 retain full jurisdiction to review all costs charged to construction projects, 10 including AFUDC, and to determine whether such costs are properly borne by 11 ratepayers. Although the use of "20/20 hindsight" should be avoided, it is 12 reasonable to evaluate construction decisions and construction cost recovery 13 on the basis of what the utility "knew or should have known" during the 14 planning and construction periods. 15 D. INFORMATION HELCO KNEW OR SHOULD HAVE 16 **KEAHOLE:** 17 KNOWN. 18 IN DISCUSSING THE BASIS FOR DISALLOWING A PORTION OF THE 19 Q. 20 AFUDC CAPITALIZED ON THE RECENT GENERATION ADDITIONS AT 21 KEAHOLE, YOU INDICATED THAT THE REGULATORY PROCESS 22 SHOULD REASONABLY CONSIDER INFORMATION THAT HELCO "KNEW 23 OR SHOULD HAVE KNOWN" DURING THE PLANNING AND STARTUP OF 24 THE KEAHOLE PROJECT AND SHOULD AVOID RELIANCE ON "20/20

HINDSIGHT." DO YOU BELIEVE THAT THE CONSUMER ADVOCATE'S
PROPOSED AFUDC DISALLOWANCE IS CONSISTENT WITH THOSE
CONCEPTS?

Yes. In evaluating the investment in the Keahole expansion that should be included in rate base, the information that was known or knowable to HELCO during the planning and early construction stages should be evaluated and considered. While I do recognize that outside factors contributed to multiple starts and stops and delays in the actual construction schedule, I believe ample evidence was known in the late 1980's and early 1990's that should have indicated that a streamlined permitting process and fast-track construction at Keahole were both unlikely. Furthermore, I do not believe that the construction delays were solely caused by external forces, completely unavoidable, or totally outside HELCO's control or influence.

While I do not disagree that external forces contributed to project delays, it does not require "20/20 hindsight" to conclude that HELCO materially contributed to events leading to the protracted construction schedule. Consequently, ratepayers should not be required to pay for excessive AFUDC resulting from material delays in constructing Keahole CT-4 and CT-5.

Α.

1	Q.	PLEASE EXPLAIN WHY YOU BELIEVE HELCO HAS MATERIALLY
2		CONTRIBUTED TO THIS SITUATION.
3	Α.	At my request, Consumer Advocate personnel conducted a review of various
4		historical documents addressing site availability and generation construction
5		constraints that were presented to the HPUC during the late 1980's and early
6		1990's. This period was selected because it coincides with the very time
7.		frame HELCO would have been exploring its capacity needs and evaluating
8		generation alternatives. By reviewing information that was known or
9		knowable during that time frame, it is possible to assess HELCO's actions in
10		that context without resorting to undesirable 20/20 hindsight. The following
11		outline presents excerpts from the referenced exhibits appended to my direct
12		testimony:
13		
14 15 16		 Exhibit CA-309. [August 1988, West Hawaii Site Study, Docker No. 7048]
17 18 19 20 21 22 23 24		KEAHOLE POWER PLAN <u>Visual Impact</u> . This site would result in the expansion of the existing power plant. It is adjacent to the Queen Kaahumanu Highway at the entrance to the Keahole Airport. This area serves as a gateway to the island and therefore is a visually sensitive location. There is insufficient opportunity for visual buffers.
25 26 27 28 29		Land Use. Currently, the zoning for this site is conservation. This designation has complicated the permitting process for the existing facilities. It would likely be difficult to obtain the necessary approvals for significant plant expansion.
30	•	The Keahole Power Plant site is close to the airport, and thus

would be subject to height and other airport-related restrictions. These include requirements to assure visibility, including night lighting and painting of stacks so they can be easily seen.

These requirements are incompatible with the need to visually buffer the <u>facility from surrounding land uses and passing motorists</u>.

[Exhibit CA-309, p. 4, Emphasis Added]

Exhibit CA-310. [January 1990, Puna Combustion Turbine Study, Docket No. 6643, HELCO-309]

If additional geothermal is not available after the initial 25 mw development, then, HELCO must plan on installing another combustion turbine (CT4), preferably at a new West Hawaii site in 1995. CT4 is recommended for installation on the west side of the island, since it will preclude the installation of additional cross-island transmission lines... However, if <u>a new West Hawaii generation site</u> is not available by 1995, and if additional geothermal is not available, CT4 could be planned for installation at Puna Power Plant. This would mean that a 5th cross-island line from Kuamana-Keamuku would need to be constructed and in service by 1995.

[Exhibit CA-310, p. 3, Emphasis Added]

Puna Power Plant was selected as the site for installing CT3 since it has sufficient land area and existing transmission facilities to accommodate the installation of a peaking unit. This will result in the minimum facility additions at least cost to HELCO. Also, it is anticipated environmental constraints at Puna would be less severe than at other HELCO power plants and the permitting process would be less likely to be encumbered by unforeseen delays.

[Exhibit CA-310, pp. 3-4, Emphasis Added]

<u>Exhibit CA-311</u>. [August 1990, HELCO T-3, Docket No. 6643]
 A Senior Planning Engineer in HECO's System Planning Department filed testimony with the Commission discussing HELCO's rationale for adding a 20 MW combustion turbine (CT-3) at Puna.

The Puna power plant is **the only existing site which does not have significant constraints** associated with the installation of a new generating unit. All other existing plant sites have encountered opposition from adjacent property owners due to noise and emissions from generating units

installed at those sites. It is expected that any new unit 1 2 addition at these plants would encounter considerable 3 opposition from the community. 4 [Exhibit CA-311, p. 3, Emphasis Added] 5 6 HELCO T-3 elaborated on noise and/or odor complaints at several 7 sites (e.g., Kanoelehua, Waimea and Keahole): 8 9 Lastly, the Keahole site also has had emission complaints registered by tenants of an adjacent agricultural park. 10 11 addition, HELCO has been instructed by DLNR that after the addition of CT2 no future unit additions would be permitted 12 at that site. 13 14 [Exhibit CA-311, p. 4, Emphasis Added] 15 16 Exhibit CA-312. [November 1991, Letter from Warren Lee to HPUC, 17 Docket No. 70481 18 19 Letter informed Commission of HELCO's issuance of letter-of-intent to 20 purchase Unit H1B (CT-4) from Stewart and Stevenson. 21 22 HELCO also expects to benefit from earlier discussions with the 23 various regulatory agencies for permit application approvals that are required before HELCO can begin to construct and 24 25 The selection of the combustion turbine operate CT-4. generator is the first step in obtaining the necessary engineering 26 27 data that are required for the ATC/PSD permit application. 28 HELCO's selection of the S&S packaged GE LM2500 29 combustion turbine generator may facilitate earlier preparation of the DOH and EPA air quality permit application. 30 31 issuance of the ATC/PSD final permit is the critical path item 32 for both HELCO's CT-3 and MECO's combined cycle generation 33 unit addition projects and is also expected to be one of the

critical path items for this CT-4 project which is currently

scheduled for commercial operation by April 1994.)

[Exhibit CA-312, p.2, Emphasis Added]

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 Exhibit CA-313. [December 1992, Consumer Advocate Statement of Position, Docket No. 7048, p.3]

The Statement of Position was filed in lieu of written direct testimony. Although the Consumer Advocate did not object to HELCO's expressed need for capacity or the type of generation selected, the filed comments included the following excerpt:

It is too early to tell whether HELCO will be forced to again relocate the CT-4 site due to community opposition to the current Keahole location of the project. Recent articles in West Hawaii Today a position paper submitted to the Commission by the Kona-Kohala Chamber of Commerce suggest that residents of the Kona area are strongly opposed to the proposed location of CT-4 at Keahole. . . . Strident local opposition to expansion at the Keahole site could, at the very least, result in delays in the anticipated November 1994 commercial operation date for the unit. The worst-case scenario in terms of securing additional generation as expeditiously as possible would occur if opponents of the Keahole site were able to force another relocation of the project. HELCO should reevaluate its decision to locate CT-4 at Keahole. Selection of another, more viable site at this time may result in less delay in securing needed generation expansion than if HELCO continues with the Keahole site only to ultimately be denied land use permits and to have to restart the project from that date.

If community opposition to the location of CT-4 at Keahole results in further delays in permitting and/or construction of the unit, additional costs to expedite installation of CT-4 may be generated. The Consumer Advocate is concerned that any expenses associated with an expedited construction and installation schedule be included in HELCO's rate base only if the delay that generated the expense was not caused by imprudence on HELCO's part. [Exhibit CA-313, pp.4-5, Emphasis Added]

Since HELCO has not expressed a firm date on which it will file its application for the ATC/PSD permits for the CT-4 project; it is difficult to assess whether the ultimate issuance of the permits will be delayed as a result. However, if delays in providing DOH with timely or sufficient meteorological data result in a delay in the issuance of the air quality permits for CT-4 and,

consequently, in increased project expenses, the CA may argue that HELCO should not be allow [sic] to recover such additional expenses from ratepayers.

During the important planning and evaluation period (1988-1991), significant concerns had been raised internally within the Company and by outside

8 parties about locating new generation at the Keahole site. Community

[Exhibit CA-313, pp.6-7, Emphasis Added]

opposition and permitting concerns should have raised early questions

regarding the ability to fast-track the construction of CT-4 and CT-5. In my

opinion, HELCO "knew or should have known" that the permitting process

would be on the construction critical path, that its selection of the Keahole site

would be contested, and that obtaining the required permits for significant

expansion of the Keahole site would be difficult.

The above document excerpts illustrate clearly visible signs that an expedited construction schedule, much less a construction schedule comparable to HELCO's then recent experience with CT-3 at Puna, was unlikely. In fact, the Consumer Advocate's comments in December 1992 were rather prophetic. Instead of completing Keahole CT-4 in 1994, the project was completed on a protracted schedule resulting in the unit becoming commercially available in May 2004 – a ten (10) year delay in the construction schedule. Consequently, the circumstances leading to the Consumer Advocate's proposed disallowance of AFUDC should not now be of surprise, or a matter of first impression, to HELCO or the Commission.

1 VI. <u>KEAHOLE: LEGAL, NOISE, LANDSCAPING & REZONING.</u>

- Q. PLEASE DESCRIBE CA ADJUSTMENTS B-8 AND C-18.
- 3 Α. This testimony section addresses HELCO's proposed rate base inclusion of 4 certain additional Keahole costs relating to legal costs, noise abatement, 5 landscaping costs and land rezoning costs. CA Adjustment B-8 6 (Exhibit CA-101) removes a portion of these costs plant in service and 7 quantifies the related impact on the accumulated depreciation reserve. Since 8 Keahole CT-4 and CT-5 were closed to plant in service in 2004, 9 CA Adjustment C-18 (Exhibit CA-101) removes depreciation on the disallowed costs from test year expense.⁵¹ 10

An earlier testimony section specifically addressed the Consumer Advocate's recommendation that a portion of the AFUDC associated with Keahole CT-4/CT-5 and common facilities be excluded from overall revenue requirement.⁵²

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- 16 Q. PLEASE EXPLAIN THE BASIS FOR THIS ADJUSTMENT.
- 17 A. The latest generation additions at Keahole, Units CT-4 and CT-5, have an extensive planning, regulatory and litigation history that dates back to the late

Since the Keahole generating units and common facility investments were closed to plant in 2004, there should be a companion pro rata adjustment to the test year balance of the accumulated deferred income tax reserve for the depreciation timing difference. Information was not readily available to quantify this impact at the time of the Consumer Advocate's filing.

⁵² CA Adjustments B-7 and C-17 (Exhibit CA-101).

1980's. In a "West Hawaii Site Study" issued in August 1998,⁵³ the consulting firm retained by HELCO screened thirteen (13) different sites and eliminated six (6) sites from further consideration. Of those six sites, the Keahole Power Plant was the first of the eliminated sites discussed in the study. According to Decision and Order No. 13050 (Docket No. 7048), the study had extensive community input and narrowed the field down to four sites.⁵⁴ Even though it was recognized that HELCO may still experience permitting problems, the Commission ultimately approved the commitment of funds to construct CT-4 at Keahole in January 1994, generally due to the difficulty of acquiring land at the other sites and Keahole being the only alternative site to possibly meet HELCO's generation needs in 1994.⁵⁵

As has been previously established, Keahole CT-4 and CT-5 became commercially available in May and June 2004 – ten years later. Needless to say, permitting problems and related litigation played a major role in that delay. In attempting to assess ratepayer responsibility, there are several important questions that defy easy answers:

Are the legal costs HELCO incurred for land use permitting and related
 litigation reasonably the responsibility of ratepayers?

The "West Hawaii Site Study" was prepared by CH2M Hill, issued in August 1988 and filed in Docket No. 7048. Excerpts from this study are included in Exhibit CA-309.

Two suitable sites at Kawaihae, a site at the county landfill at Puuanahulu and elimination of the Muheenue Cone site.

Decision and Order No. 13050 (Docket No. 7048), pp. 10-12.

- Could HELCO have avoided the extensive noise abatement and landscaping costs at a different location or if it had sought to rezone the Keahole site or had it purchased noise easements from adjoining land owners early in the project?
- Had HELCO chosen an alternate site for CT-4 (and CT-5), could the units have been completed and brought on-line sooner even though HELCO did not own property at the time?
- Instead of attempting to amend its Conservation district use permit,
 should HELCO have sought to rezone the Keahole site from conservation to an Urban-Industrial land use district?

Each of these questions is difficult to answer. However, as discussed in an earlier testimony section, it is my opinion that HELCO knew or should have known, based on facts and circumstances as they existed in the late 1980's and early 1990's, that expanding the Keahole site with additional generation would be a difficult undertaking. With that in mind, reasonable people may differ on how to answer the above questions. While it is admittedly judgmental, I believe that it is unlikely that HELCO could have avoided all of the Keahole legal, noise abatement, landscaping and rezoning costs, but I also believe that it is likely that the costs incurred would have been far less than the amounts actually incurred.

Referring to CA-IR-244, HELCO explained why it was necessary to reclassify the Keahole site from "conservation" to "urban." First, HELCO states that BLNR orders (i.e., March 2002 and October 2003) and a

November 2003 Settlement Agreement required the Company to rezone the property. Second, the Conservation classification limited HELCO's ability to make improvements at Keahole, including the installation of ST-7. Third, the reclassification and rezoning was more consistent with its industrial use, even though industrial use was permitted under the Conservation classification.

As indicated in the response to CA-IR-386 and through out the historical discussion of permitting problems and litigation discussed in HELCO-1501, significant legal fees were incurred during the lengthy delays surrounding the completion of CT-4 and CT-5.

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A. KEAHOLE - LEGAL COSTS.

- 12 Q. HOW DID YOU QUANTIFY THE PORTION OF THE ADJUSTMENT

 13 RELATED TO HELCO'S LEGAL LAND USE PERMITTING FEES?
- A. Since I am unable to conclude that 100% of those legal fees would have been avoidable, had HELCO selected a different expansion option, I have judgmentally concluded that a 50% disallowance is a reasonable compromise between balancing the interests of ratepayers with those of the Company.

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B. KEAHOLE - NOISE ABATEMENT

- 20 Q. PLEASE GENERALLY EXPLAIN THE CONCERN WITH COSTS
 21 ASSOCIATED WITH NOISE ABATEMENT.
- A. At pages 63-66 of HELCO-1501, the Company discusses the changes in noise monitoring procedures and rules that resulted in extensive costs to

reduce noise leakage from Keahole into surrounding areas. Various early decisions by the Company appear to have contributed to the litigation and ultimate incurrence of these costs, including the fast-track construction plan, expedited order of the combustion turbine, not purchasing land easements from adjoining property owners and decisions to continue efforts seeking to amend the Conservation permit.

As indicated in the response to CA-IR-501(i), the reclassification of the Keahole site "from the State Conservation District and rezoning to the County Industrial Zoning District (the process recently completed for the Keahole site), the applicable noise standard would be 70 dBA . . . the same as the written condition of the CDUP as of 1993...However, the Settlement Agreement requires that HELCO will meet the 55 dBA (daytime) and 45 dBA (nighttime) Class A Zoning District noise standards for the normal operation of the Keahole Station."

Basically, had HELCO sought to rezone Keahole early in the process, rather than continue the fight to amend the CDUP, the noise abatement cost could have been largely. if not totally avoided. However, as with the legal costs discussed previously, I have judgmentally concluded that a 50% disallowance is a reasonable compromise.

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- Q. WHAT WAS THE AMOUNT FOR LANDSCAPING COST HELCO
 ORIGINALLY ESTIMATED FOR LANDSCAPING?
- A. According to HELCO's response to CA-IR-506, there were some landscaping costs originally included in the Civil Structural Architectural cost estimate, but the amount of such landscaping was not identified or separately listed.

Further, in 1998, HELCO spend about \$210,000 for landscaping that included planting Norfolk pine trees, coconut palms, wiliwili trees, oleander and areaca palms.⁵⁶ Subsequent to the 2003 Settlement Agreement discussed at pages 67-68 of HELCO-1501, the Company has spent an additional \$903,403 on Keahole landscaping costs.

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- 13 Q. WAS A SPECIFIC AMOUNT FOR LANDSCAPING SPECIFIED IN THE
 14 SETTLEMENT AGREEMENT?
- 15 A. No. HELCO indicates that it did not attempt to negotiate a fixed cap or 16 amount for landscaping costs, but that it had estimated that the incremental 17 cost would be about \$750,000. Consistent with the discussion of the legal 18 fees and noise mitigation costs, I am recommending that 50% of the 19 additional landscaping costs be disallowed from rate base.

D. KEAHOLE - REZONING COSTS.

2 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR REZONING COSTS.

In response to CA-IR-244, HELCO discussed the need to amend the land use district to reclassify the Keahole station from "conservation" to "urban" and to rezone the station from "open" to "general industrial." Although industrial use of the Keahole site was permitted under the "conservation" classification, such classification limited HELCO's ability to improve and make changes to existing facilities and to install ST-7. Specifically, the installation of ST-7 in the "conservation" district would have been adversely affected by the need to complete construction by an unattainable deadline; the inability to obtain another conservation district amendment to add ST-7 because of 1994 legislation (i.e., Act 270) prospectively prohibiting fossil-fuel generation in a conservation district; and the agreement to install selective catalytic reduction ("SCR") with ST-7, which was not part of the DLNR approved plans involving the default entitlement HELCO obtained in lieu of the conservation district use amendment ("CDUA")

In response to CA-IR-13(b) and CA-SIR-26(b), HELCO listed the rezoning amounts spent to date as part of the planning, permitting and engineering activities for ST-7. That list included the \$1.9 million spent on Project H0000655, Reclassification and Rezoning of Keahole Station. However, HELCO-WP-1401 shows this project as having been completed and added to plant in 2006.

Α.

- 1 Q. ARE YOU RECOMMENDING THAT 100% OF THE LAND REZONING
- 2 COSTS BE EXCLUDED FROM THE INSTALLED COST OF CT-4 AND
- 3 CT-5?
- 4 A. Yes. While I am not necessarily recommending that these land rezoning
- 5 costs should be recoverable as a component of ST-7, when and if that unit is
- 6 ultimately included in rate base, I do believe that the recoverability of such
- 7 amounts are a better topic for discussion in that docket.

- 9 VII. T&D HELCO CORRECTIONS.
- 10 Q. PLEASE DESCRIBE CA ADJUSTMENT C-14.
- 11 A. CA Adjustment C-14 (Exhibit CA-101) recognizes four revisions and
- 12 corrections proposed by HELCO T-6, Mr. Jay Ignacio, in response to
- 13 CA-IR-447. CA Adjustment C-14 sets forth each proposed item, including: a
- new program implemented in 2006 to replace transformer mounting plates
- that are prone to cracking; a new 2006 program to replace deteriorating
- manhole covers; a reduction in the cost of abandoned projects; and the
- elimination of four trouble inspector positions included in the original T&D rate
- case forecast. These four items reduce test year expense by \$131,606.

- 20 Q. HOW DID THE CONSUMER ADVOCATE BECOME AWARE OF THESE
- 21 REVISIONS?
- 22 A. In October 2006, the Consumer Advocate submitted CA-IR-447 and
- 23 CA-IR-448 requesting HELCO to identify and quantify any known revisions,

omissions, modifications or corrections to its asserted rate base, operating income, capital structure, cost of service allocations or proposed rate design. Subsequent to receipt of the responses to these information requests, the Consumer Advocate then submitted follow-up information requests or discussed certain items with Company representatives.

7 Q. IN IDENTIFYING THE FOUR ITEMS INCLUDED IN THE COMPANY'S NEW
8 ADJUSTMENT, YOU REFERRED TO THE ELIMINATION OF FOUR
9 TROUBLE INSPECTOR POSITIONS INCLUDED IN HELCO'S ORIGINAL
10 T&D RATE CASE FORECAST. PLEASE FURTHER EXPLAIN THIS ITEM.

11 A.

In its original test year forecast, the Company included four (4) new trouble inspector positions, two each for Kona and Hilo. In assembling the 2006 forecast, the Company only included expenses related to the trouble inspectors for six months since HELCO assumed that the positions would be filled by mid-year.

Although HELCO has been, and continues to be, actively recruiting to fill these positions with qualified journeyman linemen, its efforts have thus far been unsuccessful. HELCO has removed the expenses for these four positions from its test year T&D forecast. ⁵⁷

- Q. AFTER INCLUDING THESE ADDITIONAL ITEMS IN CA ADJUSTMENT
 C-14, HAVE YOU ACCEPTED THE REMAINDER OF HELCO'S T&D
 EXPENSE FORECAST?
- A. No. I have also reviewed other elements of the T&D test year forecast and propose additional adjustments for a proposed increase in training expenses and removal of vacant employee positions, which will be described in subsequent testimony sections.

9 VIII. <u>T&D – TRAINING ADJUSTMENT</u>.

10 Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-15?

11 A. In general, CA Adjustment C-15 (Exhibit CA-101) reduces the Company's
12 revised forecast of T&D training costs to the actual level incurred during 2006.
13 As discussed in HELCO T-9's response to CA-IR-447, HELCO implemented
14 changes to its T&D safety program in 2006 to address an observed trend in
15 increasing accidents and incidents. The Company's original filing included
16 \$450,143 of T&D training expense, 58 which HELCO now proposes to increase
17 to \$846,300.59

⁵⁸ Source: HELCO response to CA-SIR-35.

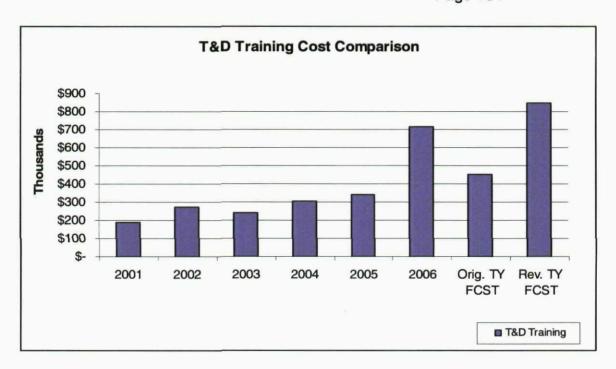
⁵⁹ Source: HELCO response to CA-SIR-37, updated 2/6/07.

- 1 Q. HAVE YOU REVIEWED ANY DOCUMENTATION RELATING TO T&D'S
- 2 EXPANDED TRAINING EFFORTS?
- 3 A. Yes. In confidential Attachments 4 through 16 of HELCO T-6's response to
- 4 CA-IR-447, the Company provided various documents related to the
- 5 expanded programs implemented in 2006 including its new Safety
- 6 Improvement Plan and Safety Recognition Program, along with various
- 7 training schedules, session outlines and planning documents.

- 9 Q. HOW DOES HELCO'S CURRENT FORECAST OF T&D TRAINING
- 10 EXPENSE COMPARE TO HISTORICAL LEVELS?
- 11 A. HELCO's revised forecast of T&D training costs is significantly higher than
- recent historical levels.⁶⁰ The following chart illustrates the significant ramp
- up in training activity in 2006, since HELCO's last rate case:⁶¹

HELCO's revised forecast of T&D training cost was included in CA Adjustment C-21 and reflected in test year A&G expense (Accounts 925 & 926). CA Adjustment C-15 reduces the Company's revised forecast.

Sources: HELCO responses to CA-SIR-35 & CA-SIR-37, updated 2/6/07.



While the Company's original 2006 forecast amount is well above all prior years but 2006 (actual), HELCO indicated in response to CA-SIR-36 that the Company first began to reevaluate its approach to T&D training after reviewing the 2005 accident and incident records.

Q. IF THE COMMISSION ALLOWS THE COMPANY TO RECOVER THE HIGHER TRAINING COSTS IN UTILITY RATES, WHAT ASSURANCE IS THERE THAT HELCO WILL CONTINUE TO SUPPORT THE PROGRAM AT THE HIGHER LEVEL WHILE THE RATES FROM THE CURRENT PROCEEDING ARE IN EFFECT?

12 A. That very question was posed to HELCO in CA-SIR-38. Basically, the Company indicated that the driver for its new program was the safety of its employees. While there has been some claimed improvement in accidents

and incidents since the expansion of the training program, HELCO indicated that training must continue at these levels for continued improvement in the future. Given the magnitude of the increase in T&D training the Consumer Advocate has proposed to include in overall revenue requirement, there is one caveat. HELCO should continue to fund its T&D training program at or near the level included in rates or be prepared to explain in future rate cases why HELCO found it necessary and appropriate to materially reduce its commitment for needed employee training, particularly after such amounts were allowed for recovery from ratepayers.

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Α.

11 Q. SHOULD THE EXPANDED T&D TRAINING PROGRAM RESULT IN
12 REDUCED ACCIDENTS, INJURY, LOST TIME, PROPERTY DAMAGE AND
13 COST SAVINGS?

Yes. I believe that such a significant expansion of safety and non-safety training should result in material benefits in the future. While it may yet be too early to pinpoint or quantify such benefits, it is reasonable to expect a reduction in incidents and a reduction in non-training costs that should mitigate the costs spent on training in future years. For this reason, I believe that the Consumer Advocate's proposal to limit T&D training costs at the 2006 actual level is reasonable. First, it helps slightly moderate the full impact sought by HELCO. Second, it is a level HELCO has attained, even without rate recovery. Finally, any future cost savings or improvement in employee efficiency will be retained by HELCO between rate cases.

1	IX.	T&D - AVERAGE EMPLOYEE ADJUSTMENT.
2	Q.	PLEASE DESCRIBE CA ADJUSTMENT C-19.
3	A.	CA Adjustment C-19 (Exhibit CA-101) revises the Company's T&D salary and
4		wage expense forecast to recognize average actual T&D employee counts for
5		2006, using standard labor rates proposed by HELCO.
6		
7	Q.	WHY DOES CA ADJUSTMENT C-19 ONLY RELATE TO T&D EMPLOYEE
8		LEVELS?
9	A.	In describing CA Adjustment C-4, Mr. Brosch (CA-T-1) discusses HELCO's
10		production labor expense forecast and describes his proposed reduction of
11		that projection to actual 2006 recorded levels. Since Mr. Brosch is separately
12		addressing production labor costs and no labor adjustments have been
13		quantified in other areas, CA Adjustment C-19 is limited to T&D employee
14		levels, trends and labor costs.
15		
16	Q.	DOES CA ADJUSTMENT C-19 ADJUST T&D LABOR COSTS TO ACTUAL
17		2006 RECORDED LEVELS?
18	A.	No. Because of the availability of sufficient data provided by HELCO.
19		CA Adjustment C-19 attempts to remove the labor costs included in the
20		Company's test year forecast for specific unfilled T&D positions by comparing
21		the Company's 2006 forecast with actual 2006 average employee counts.

As a practical matter, 2006 T&D labor costs may not necessarily be a good point of comparison. As discussed by Mr. Brosch (CA-T-1),⁶² the "...destructive earthquake that occurred on October 15, 2006 may have had a significant impact on sales in the Waimea District, which was the area of the Big Island that suffered the most damage." Since the Consumer Advocate's efforts in this rate case were focused primarily on HELCO's 2006 forecast, I did not conduct any review of the impact of the earthquake on actual T&D labor and non-labor expenses. While I do have relatively recent experience with utility costs associated with wind storms, ice storms and severe winter storms in the Midwest, I would fully expect that the October earthquake attracted significant attention from HELCO's workforce.

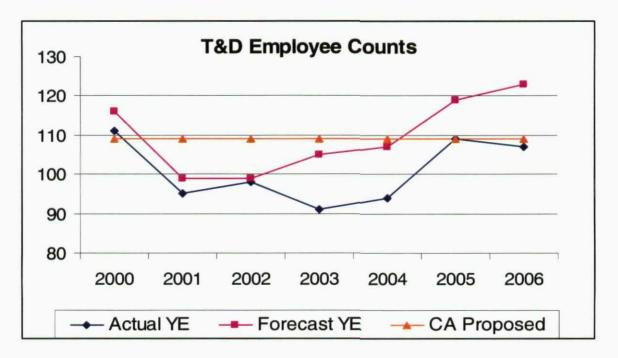
- 13 Q. HOW DOES THE LEVEL OF T&D EMPLOYEES HELCO HAS PROPOSED

 14 TO INCLUDE IN THE 2006 TEST YEAR FORECAST COMPARE WITH

 15 HISTORICAL ACTUAL AND FORECAST LEVELS?
- 16 A. The following chart shows the historical and forecast levels of T&D employees, as of calendar year-end:⁶³

In discussing the impact of the earthquake on 2006 revenues, Mr. Brosch quoted from HELCO's response to CA-SIR-3.1.

Sources: HELCO-611, HELCO-1101 and responses to CA-IR-96 & CA-IR-150.



In historical terms, HELCO has tended to over-forecast its T&D employee counts. For purposes of internal planning, it is certainly not problematic to plan and work toward hiring additional employees, provided there is a defined need for an expanded work force. However, higher is not necessarily better for ratemaking purposes. If rates are set to include labor costs for employee levels that are not actually achieved during the rate-effective period, ratepayers would be required unnecessarily pay for costs associated with additional employees that are not hired.

In the above chart, the 2006 average employee count, on which CA Adjustment C-19 is based, appears as flat horizontal line across all years. This line is equal to the 2005 year-end actual and slightly above the actual count at 2006 year-end. The Company's 2006 forecast of 123 T&D

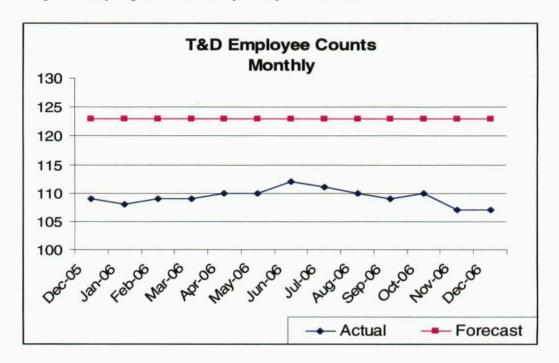
employees is materially higher than any other level actually achieved by

HELCO.

3

4 Q. THE EARLIER CHART COMPARES HELCO'S FORECAST WITH
5 HISTORICAL LEVELS AT CALENDAR YEAR-END. HOW DOES THE
6 COMPANY'S FORECAST COMPARE WITH ACTUAL MONTHLY COUNTS
7 DURING 2006?

A. As illustrated by the following chart, the Company's 2006 forecast is
 significantly higher than every test year month:⁶⁴



10

11

1	Q.	REFERRING TO THIS MONTHLY EMPLOYEE CHART, IT APPEARS THAT
2		HELCO HAS ASSUMED THAT IT WOULD ACHIEVE THE FORECAST
3		EMPLOYEE LEVEL IN JANUARY 2006 AND MAINTAIN THAT LEVEL
4		THROUGHOUT THE 2006 FORECAST YEAR. IS THAT CORRECT?
5	A.	Yes, that is generally true. There were four trouble inspector positions that
6		were included in HELCO's forecast employee level for all months, but the
7		Company only sought to include labor costs for these positions for the last six
8		months of the forecast test year, because of expected delayed hiring activity.
9		However, as discussed in a separate testimony section, the Company has
10		now removed the labor for these four positions from the 2006 forecast, but not
11		from the employee count. In any event, the actual employee count remains
2		relatively static throughout the 2006 test year.

13

14 Q. IS SUCH AN ASSUMPTION REALISTIC?

15 A. In HELCO's situation, no it is not realistic. It is common for employee
16 vacancies and the hiring of new employees to result in overall headcount
17 levels that fluctuate from month-to-month. However, there is no clear
18 evidence that HELCO's forecast level of T&D employees will be attained any
19 time soon.

20

Q. WHY SHOULD THE TEST YEAR T&D EMPLOYEE PROJECTION BE 1 2 REDUCED TO THE 2006 AVERAGE ACTUAL LEVEL? 3 Α. HELCO's projected T&D employee count is overstated by any meaningful 4 comparative measure and should be revised downward for ratemaking 5 purposes. Other than an ongoing desire to hire additional employees for its 6 T&D department, HELCO has not provided any documented support for the 7 significantly higher T&D employee level. 8 YOU PREVIOUSLY REFERRED TO THE COMPANY REVISION THAT 9 Q. 10 REMOVED THE FOUR TROUBLE INSPECTOR POSITIONS FROM THE 11 2006 LABOR COST FORECAST. IN QUANTIFYING CA ADJUSTMENT 12 C-19 DID YOU CONSIDER THIS HELCO REVISION? 13 Α. Yes. HELCO's forecast of 123 employees exceeded the test year average 14 level by 14 positions. After reducing this spread for the four trouble 15 inspectors, CA Adjustment C-19 removes labor costs associated with only 16 10 positions. 17 18 Q. WHAT TYPES OF POSITIONS DOES CA ADJUSTMENT C-19 ELIMINATE 19 FROM THE LABOR FORECAST? 20 Α. After reviewing the forecasting procedures and assumptions employed by the 21 Company to quantify its projected T&D labor costs, I compared employee 22 counts from the labor input sheets supplied in response to CA-IR-1 with the

actual employee levels in mid-2006 by division. Using this information as a guide, CA Adjustment C-19 was quantified by first identifying likely position vacancies (i.e, 2 linemen positions, 1 helper and 7 senior helpers) to provide a framework on which to base an adjustment estimate. The labor costs were calculated based on avoided hours (i.e., straight time and overtime hours), HELCO's standard labor rates for the positions (i.e., D_Techcrew and D_Crew) and the O&M expense allocation factor from HELCO's labor input sheets.

10 Q. BY REMOVING TEN (10) EMPLOYEE POSITIONS FROM THE 2006
11 FORECAST, DO YOU BELIEVE THAT THERE IS A NEED TO OFFSET THE
12 LABOR COST REDUCTION WITH HIGHER CONTRACT SERVICES THAT
13 MAY BE REQUIRED TO UNDERTAKE THE WORK PLANNED FOR THESE
14 VACANT POSITIONS?

No. Referring to HELCO-611 (employee counts) and HELCO-619 (contract services), CA-IR-97(d) sought information as to whether HELCO anticipated that the addition of 14 employee positions in 2005 and an additional 14 employees in the 2006 T&D forecast would reduce reliance on contract services. In response, the Company implied that its 2006 forecast did not recognize any reduced reliance on outside contractors and indicated that productivity can actually be reduced when new employees are hired, given

Mid-2006 employee counts by position by division were provided in response to CA-IR-96.

1		the time required to train and monitor the new employees. Had the Company
2		significantly reduced the contract services element of its 2006 test year
3		T&D O&M forecast, there might be some rationale for presuming that lower
4		headcounts could result in additional contract services. But, under the
5		circumstances, it does not appear that HELCO recognized such a reduction.
6		
7	Q.	IN DETERMINING TEST YEAR STAFFING NEEDS, DID HELCO EMPLOY
8		ANY SPECIFIC MEASUREMENT OF WORK REQUIREMENTS?
9	A.	No. As discussed by Mr. Brosch regarding production O&M, there does not
10		appear to be any objective measures of work requirements that were relied
11		upon by the Company, other than tracking historical actual work hours,
12		employee counts and contractor services.
13		
14	X.	A&G - HELCO CORRECTIONS.
15	Q.	PLEASE DESCRIBE CA ADJUSTMENT C-21.
16	A.	CA Adjustment C-21 (Exhibit CA-101) represents the Consumer Advocate's
17		proposed recognition of certain corrections and revisions proposed by
18		HELCO for Administrative and General ("A&G") expense, Accounts 920-932.
19		In response to CA-IR-447, Mr. Paul Fujioka (HELCO T-9) presented
20		various corrections, revisions and updates to the Company's original test year
21		forecast. Referring to page 7 of HELCO T-9's response to CA-IR-447, the
22		fourteen identified revisions result in a net increase to the Company's original

test year forecast of \$320,500. These items are set forth on CA Adjustment

C-21 and included in test year expense, with one exception.

3

4 Q. PLEASE EXPLAIN THAT EXCEPTION.

5 A. Although the various corrections and revisions both increase and decrease 6 expense, the largest A&G expense revision posted by Mr. Fujioka 7 HELCO T-9 relates to significant increases that HELCO T-6 has proposed for 8 T&D training costs, which were developed subsequent to the Company's 9 original filing in this proceeding. While CA Adjustment C-21 includes the full 10 value of the increased T&D training costs in A&G expense, an earlier 11 testimony section describes and quantifies the Consumer Advocate's 12 proposed revision to the T&D training cost new 13 CA Adjustment C-15).

14

- 15 XI. CAPITAL STRUCTURE & COST RATES.
- 16 Q. COULD YOU BRIEFLY IDENTIFY THE CAPITAL STRUCTURE AND COST
- 17 RATES PROPOSED BY CONSUMER ADVOCATE IN THIS CAUSE?
- 18 A. Yes. CA Schedule D of the CA Joint Accounting Schedules (Exhibit CA-101)
- sets forth the capital structure and cost rates recommended by both HECO⁶⁶

The HELCO forecast capital structure set forth on CA Schedule D represents the Company's original filed balances and cost rates, per HECO-2101. Since the CA Joint Accounting Schedules start with HELCO's "original" filing for purposes of posting the various adjustments recommended by the Consumer Advocate, it was necessary for CA Schedule D to recognize HELCO's "as filed" capital structure and cost rates, in support of the Company's overall revenue requirement.

1 and the Consumer Advocate, including the return on equity recommended by CA witness Parcell (CA-T-4). For purposes of the Consumer Advocate's 2 direct testimony and revenue requirement recommendation, CA Schedules A 3 and D (Exhibit CA-101) employ the capital structure and cost rates sponsored 4 5 by Mr. Parcell. 6 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY? 7 8 A. Yes.

STEVEN C. CARVER

Summary of Qualifications

EMPLOYER: Utilitech, Inc.

Regulatory and Management Consultants

POSITION: Vice-President

ADDRESS: 740 North Blue Parkway, Suite 204

Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

6/87 - Present Utilitech, Inc.

4/83 - 6/87 Missouri Public Service Commission, Chief Accountant
10/79 - 4/83 Missouri Public Service Commission, Accounting Manager
6/77 -10/79 Missouri Public Service Commission, Regulatory Auditor

EDUCATION:

Central Missouri State University
Bachelor of Science Degree in Business Administration
Accounting Major (1977)

State Fair Community College
Associate of Arts Degree - Emphasis in Accounting (1975)

OTHER QUALIFICATIONS:

Speaker - 1988 Missouri Public Service Commission Workshop

- 1990 Annual NASUCA/NARUC Convention (Orlando)

- 1996 Mid-Year NASUCA Meeting (Chicago)

Instructor - 1994 Hawaii Consumer Advocate Regulatory Training Program

- 1997 Hawaii Consumer Advocate Telecommunications Training Program

- 1999 Overview of Utility Regulation (Hawaii)

- 2000 Telecommunications: Overview of Regulation (Arizona)

PRIOR TESTIMONIES: (See listings attached as Exhibit CA-301.)

STEVEN C. CARVER

SUMMARY OF QUALIFICATIONS

Education and Experience

I graduated from State Fair Community College where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting. Subsequent to the completion of formal education, my entire professional career has been dedicated to public utility investigations, regulatory analysis and consulting.

From 1977 to 1987, I was employed by the Missouri Public Service Commission in various professional auditing positions associated with the regulation of public utilities. In that capacity, I participated in and supervised various accounting compliance and rate case audits (including earnings reviews) of electric, gas and telephone utility companies and was responsible for the submission of expert testimony as a Staff witness.

In October 1979, I was promoted to the position of Accounting Manager of the Kansas City Office of the Commission Staff and assumed supervisory responsibilities for a staff of regulatory auditors, directing numerous rate case audits of large electric, gas and telephone utility companies operating in the State of Missouri. In April 1983, I was promoted by the Commission to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department, providing guidance and assistance in the technical development of Staff issues in major rate cases and coordinating the general audit and administrative activities of the Department.

During 1986-1987, I was actively involved in a docket established by the Missouri Public Service Commission to investigate the revenue requirement impact of the Tax Reform Act of 1986 on Missouri utilities. In 1986, I prepared the comments of the Missouri Public Service Commission respecting the Proposed Amendment to FAS Statement No. 71 (relating to phase-in plans, plant abandonments, plant cost disallowances, etc.) as well as the Proposed Statement of Financial Accounting

Standards for Accounting for Income Taxes. I actively participated in the discussions of a subcommittee responsible for drafting the comments of the National Association of Regulatory Utility Commissioners ("NARUC") on the Proposed Amendment to FAS Statement No. 71 and subsequently appeared before the Financial Accounting Standards Board with a Missouri Commissioner to present the positions of NARUC and the Missouri Commission.

In July of 1983 and in addition to my duties as Chief Accountant, I was appointed Project Manager of the Commission Staff's construction audits of two nuclear power plants owned by electric utilities regulated by the Missouri Public Service Commission. As Project Manager, I was involved in the staffing and coordination of the construction audits and in the development and preparation of the Staff's audit findings for presentation to the Commission. In this capacity, I coordinated and supervised a matrix organization of Staff accountants, engineers, attorneys and consultants.

Since commencing employment with Utilitech in June 1987, I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water) and have been associated with regulatory projects on behalf of clients in twenty State regulatory jurisdictions.

Previous Expert Testimony

I have continued to appear as an expert witness before the Missouri Public Service Commission on behalf of various clients, including the Commission Staff. I have filed testimony before utility regulatory agencies in Arizona, California, Florida, Hawaii, Kansas, Indiana, Nevada, New Mexico, Oklahoma, Pennsylvania, Utah, and Washington. My previous experience involving major electric company proceedings includes: PSI Energy, Union Electric (now Ameren), Kansas City Power & Light, Missouri Public Service/ UtiliCorp United (now Aquila), Public Service Company of Oklahoma, Oklahoma Gas and Electric, Hawaiian Electric, and Sierra Pacific Power/ Nevada Power.

Exhibit CA-301 summarizes the various regulatory proceedings in which I have filed testimony.

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone of Missouri	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income, Affiliated Interest
Kansas City Power & Light	Missouri	PSC	ER-80-48	Staff	1980	Operating Income, Fuel Cost
Gas Service Company	Missouri	PSC	GR-80-173	Staff	1980	Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-80-256	Staff	1980	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-85	Staff	1981	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-154	Staff	1981	Interim Rates
Gas Service Company	Missouri	PSC	GR-81-155	Staff	1981	Operating Income
Gas Service Company	Missouri	PSC	GR-81-257	Staff	1981	Interim Rates
Union Electric Company	Missouri	PSC	ER-82-52	Staff	1982	Operating Income, Fuel Cost
Southwestern Bell Telephone	Missouri	PSC	TR-82-199	Staff	1982	Operating Income
Union Electric Company	Missouri	PSC	ER-83-163	Staff	1983	Rate Base, Plant Cancellation Costs
Gas Service . Company	Missouri	PSC	GR-83-207	Staff	1983	Interim Rates
Union Electric Company	Missouri	PSC	ER-84-168/ EO-85-17	Staff	1984 1985	Construction Audit, Operating Income
Kansas City Power & Light	Missouri	PSC	ER-85-128/ EO-85-185	Staff	1983 1985	Construction Audit, Rate Base, Operating Income
St. Joseph Light & Power	Missouri	PSC	EC-88-107	Public Counsel	1987	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	IURC	38380	Consumer Counsel	1988	Operating Income

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income
Dauphin Consol. Water Supply Co.	Pennsylvania	PUC	R-891259	Staff	1989	Rate Base, Operating Income, Rate Design
Southwest Gas Corporation	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TO-89-56	Public Counsel	1989 1990	Intrastate Cost Accounting Manual
Missouri Public Service	Missouri	PSC	ER-90-101	Public Counsel/ Staff	1990	UtiliCorp United Corporate Structure/ Diversification
City Gas Company	Florida	PSC	891175-GU	Public Counsel	1990	Rate Base, Operating Income, Acquisition Adjustment
Capital City Water Company	Missouri	PSC	WR-90-118	Jefferson City	1991	Rehearing - Water Storage Contract
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
Public Service of New Mexico	New Mexico	PSC	2437	USEA	1992	Franchise Taxes
Citizens Utilities Company	Arizona	ACC	ER-1032-92- 073	Staff	1992 1993	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-93-37	Staff	1993	Accounting Authority Order
Public Service Company of Oklahoma	Oklahoma .	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Acquisition Adjustment
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-930074, 0307	Public Counsel/ TRACER	1994	Sharing Plan Modifications
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	TURC	39584	Consumer Counselor	1994	Operating Income, Capital Structure

				<u> </u>	<u></u>	
Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD- 940000354	Attorney General	1994	Rate Base, Operating Income
Kauai Electric Division of Citizens Utilities Company	Hawaii	PUC	94-0097	Consumer Advocate	1995	Hurricane Iniki Storm Damage Restoration
Oklahoma Natural Gas Company	Oklahoma	occ	PUD- 940000477	Attorney General	1995	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	40003	Consumer Counselor	1995	Rate Base, Operating Income
GTE Hawaiian Tel; Kauai Electric - Citizens Utilities Co.; Hawaiian Electric Co.; Hawaii Electric Light Co.; Maui Electric Company	Hawaii	PUC	95-0051	Consumer Advocate	1996	Self-Insured Property Damage Reserve
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	94-0298	Consumer Advocate	1996	Rate Base, Operating Income
Oklahoma Gas and Electric Company	Oklahoma	OCC.	PUD- 960000116	Attorney General	1996	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC .	PUD-0000214	Attorney General	1997	Rate Base, Operating Income
Arizona Telephone Company (TDS)	Arizona	ACC	U-2063-97-329	Staff	1997	Rate Base, Operating Income, Affiliate Transactions
US West Communications	Utah	UPSC	97-049-08	Committee of Consumer Services	1997	Rate Base, Operating Income

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Missouri Gas Energy	Missouri	PSC	GR-98-140	Public Counsel	1998	Revenues, Uncollectibles
Sierra Pacific Power Company	Nevada	PUCN	98-4062 98-4063	Utility Consumers Advocate	1999	Sharing Plan
Hawaii Electric Light Co., Power Purchase Agreement (Encogen)	Hawaii	PUC	98-0013	Consumer Advocate	1999	Keahole CT-4/CT-5 AFUDC, Avoided Cost
Kansas City Power & Light Company	Missouri	MoPSC	EC-99-553	GST Steel Company	1999	Complaint Investigation
US West Communications	New Mexico	NM PRC	3008	PRC Staff	2000	Rate Base, Operating Income
Hawaii Electric Light Company	Hawaii	PUC	99-0207	Consumer Advocate	2000	Keahole pre-PSD Common Facilities
US West/ Qwest Communications	Arizona	ACC	T-1051B-99- 105	Staff	2000	Rate Base, Operating Income
The Gas Company	Hawaii	PUC	00-0309	Consumer Advocate	2001	Rate Base, Operating Income, Nonreg Svcs.
Craw-Kan Telephone Cooperative, Inc.	Kansas	KCC	01-CRKT-713- AUD	KCC Staff	2001	Rate Base, Operating Income
Home Telephone Company, Inc.	Kansas	KCC	02-HOMT- 209-AUD	KCC Staff	2002	Rate Base, Operating Income
Wilson Telephone Company, Inc.	Kansas	KCC	02-WLST-210- AUD	KCC Staff	2002	Rate Base, Operating Income
SBC Pacific Bell	California	PUC	01-09-001 / 01-09-002	Office of Ratepayer Advocate	2002	New Regulatory Framework / Earnings Sharing Investigation
JBN Telephone Company	Kansas	KCC	02-JBNT-846- AUD	KCC Staff	2002	Rate Base, Operating Income

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed	
Kerman Telephone Company	California	PUC	02-01-004	Ratepayer Advocate		General Rate Case, Affiliate Lease, Nonregulated Transactions	
S&A Telephone Company	Kansas	KCC	03-S&AT-160- AUD	KCC Staff	2003	Rate Base, Operating Income, Nonreg Alloc	
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counselor	2003	Rate Base, Operating Income, Nonreg Alloc	
Arizona Public Service Company	Arizona	ACC	E-10345A-03- 0437	ACC Staff	2004	Rate Base, Operating Income	
Qwest Corporation	Arizona	ACC	T-01051B-03- 0454 & T- 00000D-00- 0672	ACC Staff 2004		Rate Base, Operating Income, Nonreg Alloc	
Verizon Northwest Inc.	Washington	WUTC	UT-040788	Attorney General/ AARP/ WeBTEC	2004	Rate Base, Operating Income	
Public Service Company	Oklahoma	OCC	PUD- 200300076	Attorney General	2005	Operating Income	
Hawaiian Electric Company	Hawaii	PUC	04-0113	Consumer Advocate	2005	Rate Base, Operating Income	
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counselor	2005	Operating Income, Benchmarking Study	
AmerenUE d/b/a Union Electric Co.	Missouri	MoPSC	ER-2007-0002	State of Missouri	2006	Revenue Requirement	
Hawaii Electric Light Company	Hawaii	PUC	005-0315	Consumer Advocate	2007	Rate Base, Operating Income, & Keahole Units	

HAWAII ELECTRIC LIGHT COMPANY, INC. DOCKET NO. 05-0315

Historical Comparison Of Pension Costs, Contributions & Prepaid Pension Asset Balances

Year	Beginning Pension Asset Balance	NPPC_	Trust Contribution	Ending Pension Asset Balance		
	(A)	(B)	(C)	(D)		
1987	\$ 0	\$ 1,790,000	\$ 1,790,000	\$ 0		
1988	0	1,788,000	1,788,000	0		
1989	0	1,832,000	1,832,000	0		
1990	0	1,981,000	1,981,000	0		
1991	0	2,109,000	2,109,000	0		
1992	0	2,207,000	2,207,000	0		
1993	0	2,227,000	2,227,000	0		
1994	0	2,571,000	2,571,000	0		
1995	0	1,827,000	1,827,000	0		
1996	0	2,531,000	2,531,000	0		
1997	0	2,222,000	2,222,000	0		
1998	0	1,102,000	1,482,000	380,000		
1999	380,000	468,000	0	(88,000		
2000	(88,000)	(3,107,000) 0	3,019,000		
2001	3,019,000	(3,399,000) 0	6,418,000		
2002	6,418,000	(2,557,000) 0	8,975,000		
2003	8,975,000	1,498,000	3,621,000	11,098,000		
2004	11,098,000	76,000	4,868,000	15,890,000		
2005	15,890,000	875,000	500,000	15,515,000		
2006 Est.	15,515,000	2,744,000	0	12,771,000		
Totals		\$ 20,785,000	\$ 33,556,000			
2005- 2006 Avg.				\$ 14,143,000		
2000- 2002 Sum		\$ (9,063,000)	<u>\$</u> 0	\$ 9,063,000		
	Year Average Prepairs		et .	64.08%		

Source: HELCO response to CA-IR-464, p. 60.

HAWAII ELECTRIC LIGHT COMPANY, INC. DOCKET NO. 05-0315 HISTORICAL ANALYSIS OF PENSION COSTS INCLUDED IN REVENUE REQUIREMENT

						Total NPPC -	- Before Allocation	Between Expense	& Capital/Other	
Line No.	Year	HPUC Docket/Decision	Test Year	D&O Effective Date	Assumed Months in Effect	Total NPPC Rate Case Allowance (a)	Prorated Total NPPC In Rates	Prorated Actual Total NPPC	"()" Denotes Total NPPC Net Ratepayer Benefit	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	
1	1991	6432/10993	1990	03/15/91	9.57	\$ 1,700,000	\$ 1,355,342	\$ 1,681,422	\$ (326,079)	
2 3	1992 1992	6999/11893	1992	10/09/92	9.28 2.72	1,700,000 2,213,000	1,314,481 501,855	1,706,505 500,495	(392,025) 1,361	
4	1993				12.00	2,213,000	2,213,000	2,227,000	(14,000)	
5	1994				12.00	2,213,000	2,213,000	2,571,000	(358,000)	
6 7	1995 1995	7764/13762	1994	02/13/95	1.45 10.55	2,213,000 2,538,000	266,773 2,232,049	220,241 1,606,759	46,532 625,290	
8	1996				12.00	2,538,000	2,538,000	2,531,000	7,000	
9 10	1997 1997	94-0140/15480	1996	04/07/97	3.19 8.81	2,538,000 2,446,000	674,482 1,795,967	590,504 1,631,496	83,978 164,471	
11	1998				12.00	2,446,000	2,446,000	1,102,000	1,344,000	
12	1998				12.00	2,446,000	2,446,000	468,000	1,978,000	
. 13	2000				12.00	2,448,000	2,446,000	(3,107,000)	5,553,000	
14 15	2001 2001	99-0207/18365	2000	02/15/01	1.51 10.49	2,446,000 (3,002,000)	308,263 (2,623,666)	(428,367) (2,970,633)	738,630 346,967	
16	2002				12.00	(3,002,000)	(3,002,000)	(2,557,000)	(445,000)	
17	2003				12.00	(3,002,000)	(3,002,000)	1,498,000	(4,500,000)	
18	2004				12.00	(3,002,000)	(3,002,000)	76,000	(3,078,000)	
19	2005				12.00	(3,002,000)	(3,002,000)	875,000	(3,877,000)	
20	2006				12.00	(3,002,000)	(3,002,000)	2,744,000	(5,746,000)	
21 22	1991-2006 1998-2006	Totals Since Rate Totals Since Pens	_	_			\$ 5,117,547 \$ (9,987,403)	\$ 12,966,422 \$ (2,300,000)	\$ (7,848,875) \$ (7,687,403)	

Footnotes:

⁽a) HELCO responses to CA-IR-134 & CA-IR-270.

CONSUMER ADVOCATE PROPOSED PENSION TRACKING MECHANISM

<u>Purpose</u>: The proposed pension tracking mechanism is designed to achieve the following objectives:

- A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;
- B. Ensure that all amounts contributed to the pension trust funds (see Item 3 below) are in an amount equal to actual NPPC and are recoverable through rates; and
- C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

- 1. The amount of FAS 87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.
- 2. Except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.
- 3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons:
 - the minimum required contribution is greater than the FAS 87 NPPC,

- the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums, and
- the increased contribution was made to avoid a charge to other comprehensive income.

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

- 4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.
 - The unamortized cumulative net ratepayer benefit of approximately \$12.8 million, as of December 2006, shall be included in rate base and amortized over a five year period.
 - If the actual FAS87-determined NPPC recorded during a given rate-effective
 period is greater than the FAS87 NPPC included in rates during the
 immediately preceding rate case, the Company will establish a separate
 regulatory asset account to accumulate such difference, but only to the extent
 that such amount is not used to reduce a regulatory liability recorded pursuant
 to Item 5.
 - If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.
 - If the actual FAS87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., \$0).
 - Since this is considered to be a <u>cash</u> item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.
- 5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability

will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

- If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., \$0).
- If NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., \$0).
- Since this regulatory liability is considered to be a <u>non-cash</u> item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.
- The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.
 - The Company will establish a separate regulatory asset account to offset any charge that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.
 - This regulatory asset will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this proposal, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.
 - The regulatory asset will increase or decrease each year by the same amount that the equity charge increases or decreases.

- 7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless whether the term is longer or shorter than five years.
 - If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case over a five year period and any unamortized balance shall be included in rate base.
 - If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.
- 8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will <u>not</u> be included in Rate Base in any future rate case, except for the unamortized portion of the \$12.8 million of cumulative net ratepayer benefits previously identified. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

Comments & Clarifications Regarding the Consumer Advocate's Proposed Pension Tracking Mechanism

- The proposed tracking mechanism refers to "NPPC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 net periodic costs.
- 2. "NPPC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.
- 3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 net periodic costs determined for each calendar year.
- 4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS87 net periodic costs determined for a given year and the amount of such costs included in then existing utility rates.
- 5. The provisions of FAS87 may require a company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

- a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future prepaid pension asset resulting from an actuarial study that resulted in "negative" net periodic costs.
- b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., \$0).
- 6. If the utility is allocated a portion of the FAS87 <u>net periodic costs</u> from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to funding 100% of the FAS87 <u>net periodic costs</u> for both HELCO and the affiliate <u>or</u> to maintain segregated pension trust funds for each entity in order to avoid any funding conflicts or issues that might arise in the future.
- 7. Any commitment by HELCO to fund 100% of its FAS87 net periodic costs will not be contingent on implementing a substantially similar tracking mechanism for each HELCO affiliate. However, in future rate proceedings, the Consumer Advocate will propose that a substantially similar pension tracking mechanism be implemented by HELCO's affiliates.

CONSUMER ADVOCATE'S PROPOSED PENSION TRACKING MECHANISM ILLUSTRATION -- SCENARIO 1

Exhibit CA-306 Docket No. 05-0315 Page 1 of 3

Line No.	Description	NPPC In Rates	Actual NPPC	Contribution	Prepaid Per Current Year	nsion Asset Cumulative	Regulate Current Year	ory Asset Cumulative	Regulatory Current Year	Liability 1 Cumulative	Regulator	Liability 2 Cumulative
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	(J)	(K)	(L)
1 2 3 4	Scenario 1; NPPC included in rates Min. Contrib. (Year 1) Min. Contrib. (Year 2+)	\$ 2,000,000 \$ - \$ -										
5 6 7 8 9	Actual NPPC Year 1 Year 2 Year 3 Year 4 Year 5	\$ 2,000,000 2,000,000 2,000,000 2,000,000 2,000,000	\$ 3,000,000 2,000,000 2,000,000 2,000,000 1,500,000 \$ 10,500,000	\$ 3,000,000 2,000,000 2,000,000 2,000,000 1,500,000 \$ 10,500,000	\$ - - - -	\$.	\$ 1,000,000 - - - (500,000)	\$ 1,000,000 1,000,000 1,000,000 1,000,000 500,000	\$ - - - -	\$ - - - - -	\$ - - - -	\$ - - - - -

Assuming Year 5 is the test year for the "next" rate case, NPPC of \$1.5 million would be included in rates.

The average test year regulatory asset balance (i.e., \$.75 million) would be included in rate base in the "next" rate case.

^{=&}gt; The regulatory asset balance at test year-end (i.e., \$.5 million) would be amortized over five years and included in the "next rate case (i.e., positive \$100,000).

CONSUMER ADVOCATE'S PROPOSED PENSION TRACKING MECHANISM ILLUSTRATION -- SCENARIO 2

Exhibit CA-306 Docket No. 05-0315 Page 2 of 3

Line	Danadati	NPPC	Actual	On all the Alam	Prepaid Pe		Regulato		Regulatory		Regulator	
No.	Description	In Rates	NPPC	Contribution	Current Year	Cumulative	Current Year	Cumulative	Current Year	Cumulative	Current Year	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	(7)	(K)	(L)
1	Scenario 2:											
2	NPPC included in rates	\$ 2,000,000										
3	Min. Contrib. (Year 1)	\$ 2,000,000										
4	Min. Contrib. (Year 2+)	s -										
5	Actual NPPC											
6	Year 1	\$ 2,000,000	\$ 1,000,000	\$ 2,000,000	\$1,000,000	\$1,000,000	\$ -	\$ -	\$ (1,000,000)	\$ (1,000,000)	\$ -	\$
7	Year 2	2,000,000	2,000,000	1,000,000	(1,000,000)	-	_	_	-	(1,000,000)	-	_
8	Year 3	2,000,000	2,000,000	2,000,000	-	•	-	_	-	(1,000,000)	_	_
9	Year 4	2,000,000	2,000,000	2,000,000	-	•	_	-	-	(1,000,000)	-	-
10	Year 5	2,000,000	2,000,000	2,000,000	-	-	=	_	-	(1,000,000)	-	-
		\$ 10,000,000	\$ 9,000,000	\$ 9.000,000								

Assuming Year 5 is the test year for the "next" rate case, NPPC of \$2.0 million would be included in rates.

Because the minimum contribution exceeded NPPC in Year 1, a prepaid pension asset was recorded. However, this additional contribution is recognized as a "credit" in determining the contribution in Year 2 (and subsequent years, if needed) so that actual NPPC and contributions are rebalanced. The prepaid pension asset would only be included in rate base if it had not been reduced to "zero" by the next rate case. No amortization would be applied.

Regulatory Liability 1 represents funds collected from ratepayers in excess of actual NPPC fund and is considered a "cash" item.

[⇒] The average test year Regulatory Liability 1 balance (i.e., \$1.0 million) would be included in rate base in the "next" rate case.

The Regulatory Liability 1 balance at test year-end (i.e., \$1.0 million) would be amortized over five years and included in the "next" rate case (i.e., negative \$200,000).

CONSUMER ADVOCATE'S PROPOSED PENSION TRACKING MECHANISM ILLUSTRATION -- SCENARIO 3

Exhibit CA-306 Docket No. 05-0315

Page 3 of 3

Ë		NPPC	•	Actual		Prepaid Pension Asset	nsion Asset	œ	Regulatory Asset	Asset	Regulatory Liability 1		Regulatory	Liability 2
ဦ	Description	in Rates		NPPC	Contribution	Current Year	Current Year Cumulative		Year	Current Year Cumulative	Current Year	Cumulative	Current Year Cumulative	Cumulative
	(V)	(B)		(2)	(<u>O</u>)	(E)	(F)	<u>(</u>		£	€	3	S	(1)
- 7 °C	Scenario 3; NPPC included in rates Min. Contrib. (Year 1)	\$ 2,000,000	н											
4	Min. Contrib. (Year 2+)		b "											
2	Actual NPPC													
9	Year 1	\$ 2,000,000	s	(200,000)	, 59	\$ 500,000 \$ 500,000	\$ 500,000	₩	,	,	\$ (2,000,000)		\$ (2,000,000) \$ (500,000) \$ (500,000)	\$ (500,000)
~	Year 2	2,000,000		2,000,000	1,500,000	(200,000)	•		,	,	•		•	(200'000)
80	Year 3	2,000,000	••	2,000,000	2,000,000	•			,	•	•	(2,000,000)		(200'000)
Φ	Year 4	2,000,000	.4	2,000,000	2,000,000	•				•	•	(2,000,000)	•	(200'000)
2	Year 5	2,000,000		2,000,000	2,000,000	•	•			•	•	(2,000,000)	•	(200,000)
		\$ 10,000,000	s	7,500,000	\$ 7,500,000									

[➡] Assuming Year 5 is the test year for the "next" rate case, NPPC of \$2.0 million would be included in rates.

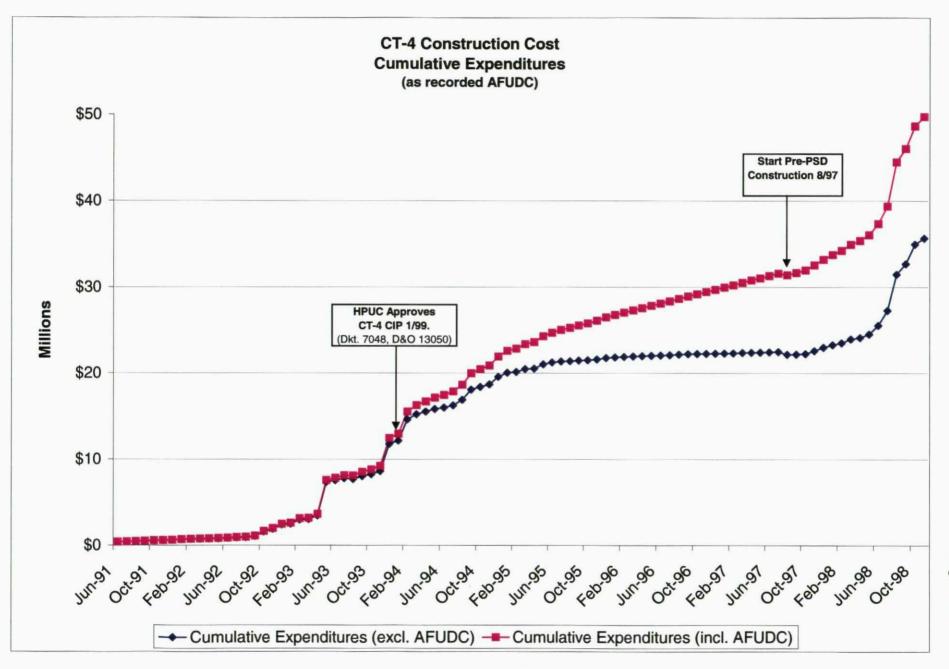
[⇒] Because NPPC was negative in Year 1 and the contribution was "zero", a prepaid pension asset was recorded. However, the pension credit is recognized as a "credit" in determining the contribution due in Year 2 (and subsequent years, if needed) so that actual NPPC and contributions are rebalanced. By reducing the Year 2 contribution, the assumption is that the \$1.5 million would exceed any required minimum contribution.

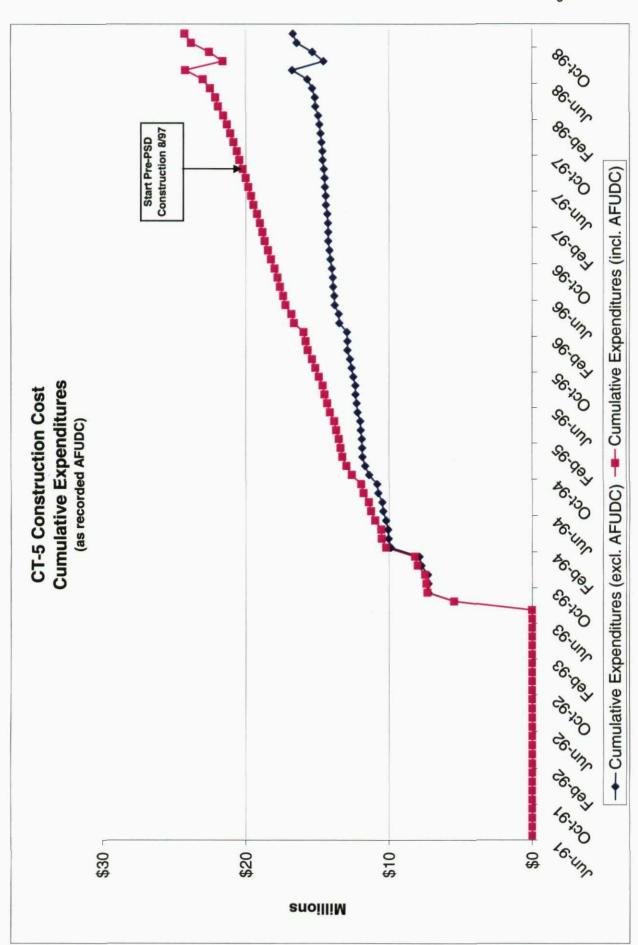
The prepaid pension asset would only be included in rate base if it had not been reduced to "zero" by the next rate case. No amortization would be applied.

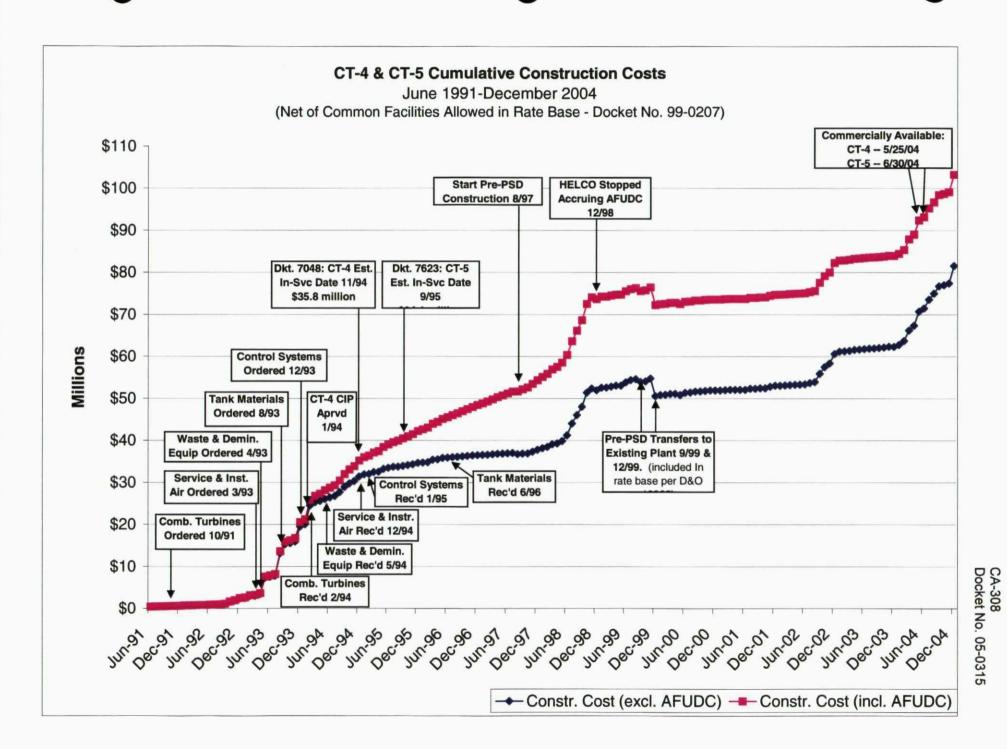
C Regulatory Liability 1 represents funds collected from ratepayers (\$2 million) in excess of actual NPPC, which can be no lower than "zero" (\$0) in any given year, and is considered a "cash" item. Regulatory Liability 2 is created by recording a positive \$500,000 accrual in Year 1 to offset the actual negative NPPC. This amount does not represents funds collected from ratepayers

and is considered a "non-cash" item. When NPPC becomes positive again (Year 2), the offsetting positive accrual is reversed and the liability is reduced. [Note: The reversal is not shown above.]

The Regulatory Liability 1 balance at test year-end (i.e., \$2.0 million) would be amortized over five years and included in the "next" rate case (i.e., negative \$400,000).





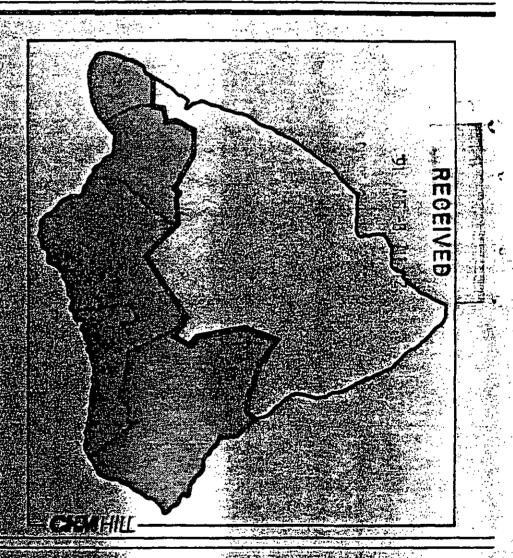


CA-309 Docket No. 05-0315 OCKET NO. 704 Page 1 of 4

HAWAIIAN ELECTRIC CO. INC. ENGINEERING LIBBARY HONOLULU, HAWAII

WEST HAWAII SITE STUDY

PROJECT



AUGUST 1988

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Section 3 SITE IDENTIFICATION AND EVALUATION

In this section, the process used to identify and evaluate potential sites for future power generation is described. The first phase of this process consisted of gathering data about the study area and developing general criteria for the initial screening of West Island areas. The second phase included area reconnaissance, visits to potential sites, development and application of site evaluation criteria, and evaluation and ranking of sites. Figure 3-1 is a flow chart illustrating the study process.

COMMUNITY ADVISORY GROUP

Participation of a Community Advisory Group (CAG) was integral to the site identification and evaluation process. The CAG met at Kailua-Kona on three occasions to review study progress and provide input concerning various project elements. The CAG also participated in site visits. Members of the CAG are listed in Appendix A. They include property owners, governmental representatives, residents of the project area, resort owners, and representatives of various interest groups.

At the first CAG meeting, members discussed the need for power generation, the study area, power system elements, the study process methodology, area screening criteria, and site selection and evaluation criteria. The second meeting consisted of further discussion of site evaluation criteria, a review of 13 potential sites, and a review of major issues concerning site selection and potential impacts. The third meeting was held to discuss the final screening to four alternative sites and the primary issues being studied for each site. Minutes from each meeting are included in Appendix A.

DEVELOPMENT OF AREA CRITERIA

The first step in the selection of possible sites for new power generation was the development of general area criteria. The purpose of these criteria was to bring potential sites into focus by identifying constraints to site location. Through area criteria, fatal flaws were identified and portions of the study area were eliminated from further consideration. The area criteria used in this analysis are listed in Table 3-1.

SCREENING FROM 13 TO 7 SITES

After the site field visits by the technical team and CAG members, the 13 sites were screened. Six were eliminated, leaving seven potential sites (see Figure 3-8). The six sites that were eliminated from further consideration, as well as the principal reasons for their elimination, are described in the following discussions.

KEAHOLE POWER PLANT

Visual Impact. This site would result in the expansion of the existing power plant. It is adjacent to the Queen Kaahumanu Highway at the entrance to Keahole Airport. This area serves as a gateway to the island and therefore is a

visually sensitive location. There is insufficient opportunity for visual buffers.

The residential area mauka of this proposed site is growing. The power plant would be visible from this area. Because of the elevation differential, there would be little opportunity, if any, for visual buffering.

Land Use. Currently, the zoning for this site is conservation. This designation has complicated the permitting process for the existing facilities. It would likely be difficult to obtain the necessary approvals for significant plant expansion.

The Keahole Power Plant site is close to the airport, and thus would be subject to height and other airport-related restrictions. These include requirements to assure visibility, including night lighting and painting of stacks so they can be easily seen. These requirements are incompatible with the need to visually buffer the facility from surrounding land uses and passing motorists.

ENERGY LAB

Visual Impact. This site is located in a broad open area between the Queen Kaahumanu Highway and the ocean. This portion of the highway is heavily traveled by people coming to and from the airport. It is also located close to the Old Mamalahoa Trail (King's Trail). It would be highly visible from both the trail and the highway, with little opportunity for visual buffers.

Land Use. This site is adjacent to the Host Industrial Park, a park limited to use by alternative energy related facilities. A traditional fossil fuel power generation facility such as that proposed may be incompatible as an adjacent use.

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HAWAII ELECTRIC LIGHT COMPANY
PUNA COMBUSTION TURBINE STUDY

JANUARY, 1990 HELCO GENPP 16-5

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HAWAII ELECTRIC LIGHT COMPANY PUNA COMBUSTION TURBINE STUDY

January 1990

Prepared by:	Marid 1 Magata
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	A. K. Wakamura System Planning Manager
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	Lemes
	F. Kennedy Production Manager
	n. a On
	N y Ose

President

EXHIBIT III PAGE 5 OF 32

additional base load generation from this source while maintaining the 20 mw CT as an emergency or peaking generator.

If additional geothermal is not available after the initial 25 mw development, then, HELCO must plan on installing another combustion turbine (CT4), preferably at a new West Hawaii site in 1995. CT4 is recommended for installation on the west side of the island, since it will preclude the installation of additional cross-island transmission lines to transport power from East Hawaii to the west side. CT4 would be planned for later conversion to a base loaded combined cycle unit. However, if a new West Hawaii generation site is not available by 1995, and if additional geothermal is not available, CT4 could be planned for installation at Puna Power Plant. This would mean that a 5th cross-island line from Kaumana-Keamuku would need to be constructed and in service by 1995.

The conversion of CT3 at Puna to a combined cycle unit is not planned at this time, since it will be used primarily as an emergency and peaking unit replacing the existing 10 mw combustion turbine, CT1, at Kanoelehua.

Puna power plant was selected as the site for installing CT3 since it has sufficient land area and existing transmission

EXHIBIT III
PAGE 6 OF 32

facilities to accommodate the installation of a peaking unit. This will result in the minimum facility additions at least cost to HELCO. Also, it is anticipated environmental constraints at Puna would be less severe than at other HELCO power plants and the permitting process would be less likely to be encumbered by unforeseen delays.

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HELCO T-3 DOCKET NO. 6643

DIRECT TESTIMONY OF JEUN ODA

SENIOR PLANNING ENGINEER HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Capacity Planning Considerations and Unit Type and Size Selection

HELCO T-3 DOCKET NO. 6643 PAGE 1 OF 24

CA-311 Docket No. 05-0315 Page 2 of 4

1		INTRODUCTION
2	Q.	Please state your name and business address.
3	A	My name is Jeun Oda, and I am a Senior Planning
4		Engineer in the System Planning Department at Hawaiia
5		Electric Company, Inc (HECO). My business address is
6.		820 Ward Avenue, Honolulu, Hawaii.
7	Q.	Please provide a brief description of your relevant
8		education and experience as they relate to your
9		position.
10	Α.	I have attached as HELCO-300 a description of my
11		education and experience.
12	Q.	What is the purpose of your testimony in this
13		proceeding?
14	A.	I am participating as a witness in this docket to
15		1) summarize the need for the addition of
16		capacity to the HELCO system in 1992
17		(including a description of the proposed
18		change in HELCO's capacity planning criteria
19		and its impact on HELCO's generation
20		planning), and
21		2) summarize the analyses leading to the
22		selection of the proposed 20 MW simple cycle
23		combustion turbine unit (CT3) at HELCO's Puna
24		Power Plant.
25		The need for capacity, the change in HELCO's

HELCO T-3 DOCKET NO. 6643 PAGE 23 OF 24

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20 MW combustion turbine unit can be retrofitted
with a heat recovery steam generator and a 8 MW
steam turbine generator unit similar to the type
proposed for future HELCO combined cycle units.

CT3 could then become a 28 MW combined cycle unit
with increased fuel efficiency suitable for base
load operations.

- Q. Why was Puna power plant selected as the site for installing CT3?
- The Puna power plant is the only existing site which 10 Α. does not have significant constraints associated with 11 the installation of a new generating unit. All other 12 existing plant sites have encountered opposition from 13 adjacent property owners due to noise and emissions 14 from generating units installed at these sites. 15 expected that any new unit addition at these plants 16 would encounter considerable opposition from the 17 community. 18
- 19 Q. Can you elaborate on these complaints?
- 20 A. At the Kanoelehua site, there have been noise and odor
 21 complaints registered by workers employed by adjacent
 22 property owners. Expanding Kanoelehua with
 23 additional generation would more than likely
 24 necessitate the addition of taller stacks for existing
 25 units and also the installation of costly noise

HELCO T-3 DOCKET NO. 6643 PAGE <u>24</u> OF 24 CA-311 Docket No. 05-0315 Page 4 of 4

	damping equipment to rectify these complaints. The
	Waimea site also has had numerous complaints from
	homeowners who are bothered by the noise emitted by
	the diesels running at night. It is expected that any
	unit addition at that site will encounter considerable
	opposition from property owners and would entail
	costly noise suppressing equipment to be installed by
	HELCO. Lastly, the Keahole site also has had emission
	complaints registered by tenants of an adjacent
	agricultural park. In addition, HELCO has been
	instructed by the DLNR that after the addition of CT2
•	no future unit additions would be permitted at that
	site.

14 Q. Does this conclude your testimony?

15 A. Yes, it does.

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Warren H. W. Lee, P.E. President

November 20, 1991

The Honorable Chairman and Members of the Hawaii Public Utilities Commission Kekuanaoa Building 465 South King Street, 1st Floor Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 7048 - HELCO's CT-4 Unit Addition Letter of Intent for Procurement of Unit H1B

This is to inform the Commission that HELCO issued a letter-of-intent dated October 31, 1991 to Stewart and Stevenson Services, Inc. ("S&S") for the procurement of Unit H1B, subject to cancellation without charge prior to June 1; 1992. (See Attachment 1.) HELCO exercised its option for the procurement of Unit H1B which was offered by S&S as part of its earlier bid package that included HELCO's CT-3 and MECO's 56 MW combined cycle units. (See Attachment 2.) The terms and conditions of HELCO's letter-of-intent is subject to final agreement by the parties. (See Attachment 3.)

HELCO's decision to issue a letter-of-intent to S&S is based upon the favorable terms and conditions offered by S&S, as outlined in its September 26, 1991 letter, and the benefits that HELCO expects to realize by utilizing a S&S supplied GE LM2500 combustion turbine generator package. S&S is the same turnkey supplier of HELCO's 20 MW CT-3 and of MECO's 56 MW combined cycle projects.

HELCO expects to realize the following benefits by installing the S&S combustion turbine package: lower engineering expenses (for both the design and manufacture of the combustion turbine generator package and the design and fabrication of certain aspects of the power plant facility), lower operating and maintenance expenses for the unit because of the experience with the S&S packaged CT-3 unit (HELCO expects that a similar control package as CT-3 will be utilized for CT-4), and lower inventory cost for spare parts and specialty tools that HELCO must maintain in its inventory.

C U VC MUN 10.

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The Honorable Chairman and Members of the Hawaii Public Utilities Commission Docket No. 7048 November 20, 1991 Page 2

HELCO also expects to benefit from earlier discussions with the various regulatory agencies for permit application approvals that are required before HELCO can begin to construct and operate CT-4. The selection of the combustion turbine generator is the first step in obtaining the necessary engineering data that are required for the ATC/PSD permit application. HELCO's selection of the S&S packaged GE LM2500 combustion turbine generator may facilitate earlier preparation of the DOH and EPA air quality permit application. (The issuance of the ATC/PSD final permit is the critical path item for both HELCO's CT-3 and MECO's combined cycle generation addition projects and is also expected to be one of the critical path items for this CT-4 project which is currently scheduled for commercial operation by April 1994.)

HELCO will continue to work with the Commission, the Consumer Advocate, and Waimana Enterprises, Inc. to facilitate the timely Commission review and approval for this project, which is essential to the reliability of HELCO's service to its customers. If you have any further questions regarding this matter, please call Earl Ifuku with Hawaiian Electric Company's Regulatory Affairs Division at 543-4787.

Sincerely,

Naver Hulee

Attachments

cc: C. W. Totto

A. S.N. Hee





GENPP 4-5-1 YA/G

Attachment 1 Page 1 of 2

CA-312 Docket No. 05-0315 Page 3 of 10

October 31, 1991



Warren H. W. Lee, P.E.

Stewart & Stevenson Services, Inc. P.O. Box 1637 Houston, Texas 77251-1637

Attention: Mr. Jay C. Manning

Director, International Sales & Marketing

Gentlemen:

Subject: Hawaii Electric Light Company, Inc.

Kawaihae Combustion Turbine No. 4 S&S Letter dated September 26, 1991

We are pleased to inform you that HELCO hereby issues this Letter-of-Intent for the procurement of Unit H1B from Stewart & Stevenson for a price of \$8,750,000 and in accordance with your letter dated September 26, 1991 with the following conditions:

- 1. This Letter-of-Intent can be cancelled at anytime without any cancellation charges until June 1, 1992.
- 2. The payment and delivery schedule must be revised to reflect a required delivery to the site on August 31, 1993. We suggest the following:

	PAYMENT NO.	DATE	PERCENTAGE OF CONTRACT
1)	Notice to proceed	09/01/92	5%
2)	Production milestone	02/01/93	45 % .
3)	Delivery to site	08/31/93	50%

3. HELCO will request Stewart & Stevenson to consider several technical changes to the scope of supply for Unit H1B. These changes will be forwarded to Stewart & Stevenson at a later date.

Attachment 1 Page 2 of 2

Stewart & Stevenson Services, Inc. October 31, 1991
Page 2

CA-312 Docket No. 05-0315 Page 4 of 10

We are hopeful that these conditions will be agreeable to you. Please notify us of your acceptance by issuing us a letter of confirmation within seven days of receipt of this letter. We look forward to working with you on this new project.

Sincerely,

Naven Blile

BMN:nh

cc: F. Kennedy

C. Nagata

T. Johnson

B. Munger

B. Nakamoto



FAX: 808 543 7519



STEWART & STEVENSON SERVICES, INC.

WORLD HEADQUARTERS M.O. BOX 1607 HOUSTON, TEXAS 7725 -1657 (710) Jan TELEX: 79422 / 201446 CFW HOU FAX: 1/10) 8691/1

CA-312 Docket No. 05-0315 Page 5 of 10

September 26, 1991

Dr. Brenner Munger Hawaii Electric Company Inc. P. O. Box 2750 Honolulu, Hawaii 96840-0001

Subject:

Unit H1B for Hawaii Electric Light Company

Dear Brenner,

We understand that Hawaii Electric Light Company is considering the purchase of another gas turbine generator set to be located on the west side of the Big Island. Based upon the present contract price levels for MIA, MIB, and HIA, we calculate the price for an additional unit on the Big Island (call it Unit H1B) would be as follows:

	PRICE	Difference In Price (%)
MIA	\$7,900,859	•
H1A	\$8,827,875	5.77
MIB	\$8,357,055	5.63
HIB	s9,325,220	5.63

However, in order to help HECO pursue this project and in our continued spirit of cooperation, we are willing to make the following offer to your company

Item No. 1 The price for H1B will be \$8,750,000.

Item No. 2 HILCO gives S&S a Letter of Intent for HIB no later than

October 31, 1991.

Attachment 2 Page 2 of 4 CA-312 Docket No. 05-0315 Page 6 of 10

Dr. Brenner Munger Hawaii Electric Company Inc. September 26, 1991 Page two

Irm No. 3

HELCO has the option of canceling the Letter of Intent at any time without any cancellation charges until June 1, 1992 if it is determined that the project will not proceed.

Item No. 4

The payment schedule for H1B will be as follows:

PAYMENT NO.	DATE	PERCENTAGE OF CONTRACT
1) Notice to proceed	06/01/92	5%
2) Production of Milestone	12/01/92	45%
3) Delivery to site or 60 days from readiness to ship.	11/30/93	50%

Item No. 6 The reduced price for HiB assumes the scope of supply will be the same as HiA purchase order terms and conditions.

Item No. 7

The Letter of Intent may be extended beyond June 1, 1992 upon mutual consent of both parties and an agreed upon escalation of the price based on the new delivery date established at that time.

Brenner, if you just go through the calculations based on the above pricing, the price offered for H1B would be only a 4.7% increase over H1A, even though we could justify an 11.6% increase. The result is a savings of over 6% on unit H1B. In my opinion, this would present a very strong case for HECO to direct purchase H1B from S&S.

We are able to make this offer to HELCO due to the reduction in our engineering expenses, quicker production schedule as the drawings are already produced, and reduced factory load test due to having already tested three of these units. In addition, HELCO would see benefits from the similarity in equipment in the plant with HIA, operator training, reduction in spare parts on site, and familiarity with the equipment. HELCO should also see a benefit from the cost of the entire plant as the engineering for HIA should be able to be utilized for HIB as well,

JC146991.01

CA-312 Docket No. 05-0315 Page 7 of 10

Dr. Bremer Munger Hawaii Electric Company Inc. September 26, 1991 Page three

Brenner, I think you will agree this latest offer gives HELCO a tremendous amount of flexibility and time to determine how they are going to proceed on the purchase of the fourth unit. Obviously, the gas turbine generator set is only part of the overall cost of the installation of the unit, however it is the major cost.

In researching the LM2500 sales for the last couple of years, I used the latest G.E. experience list out of their publication AE3263(12/90). This book was published in December of 1990 and therefore does not represent the most recent sales, however it does present a strong case that S&S has been and is the dominant supplier of LM2500s in the United States and Canada for the past three years. If you exclude the international sales of the LM2500 (of which Stewart & Stevenson has a majority) and take the years 1988 through 1991, S&S has supplied 28 out of 34 units. Out of the six units that we lost, only two were competitively bid, the other four units were negotiated directly with another supplier. Therefore, it is correct to assume that S&S is the low cost producer of the LM2500, and has not lost a competitively bid job since 1988.

It can be further shown that S&S is the low cost producer of G.E. aeroderivative turbines for power generation by the fact that G.E. Corporate made a policy decision concurring the LM6000 in October of 1990 which resulted in the announcement of a new partnership between G.E. and Stewart & Stevenson. It was unnounced at that time that Stewart & Stevenson would become the exclusive packager for G.E. of the new LM6000 industrial aeroderivative gas turbine for the United States and Canada. G.E. has the exclusive rights to market the LM6000 in the U.S. and Canada and S&S will manufacture the LM6000 package for G.E. based on our package design. S&S can market and sell the LM6000 outside of the U.S. and Canada for the international marketplace. At this time, it was also announced that G.E. would no longer package the other LM series of industrial aeroderivative gas turbines.

By the way, S&S was the only packager chosen to be part of the development team on the LM6000 program when G.E. made the decision to modify the CF6-80C2 aircraft engine for industrial use and call it the LM6000. Our participation in the development program of the engine began in 1989 for the main purpose of making sure the conversion from an aircraft engine to an industrial engine would be looked at from a puckager's standpoint to enhance the maintainability and operational features of the LM6000. This again points out G.E.'s recognition that Stewart & Stevenson is the dominant packager of their LM series of engines for power generation. Of course, we are the largest packager in the world of G.E. industrial aeroderivative gas turbines for power generation with more than 100 units in service or on order.

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Attachment 2 Page 4 of 4

CA-312 Docket No. 05-0315 Page 8 of 10

Dr. Brenner Munger Hawaii Electric Company Inc. September 26, 1991 Page four

Stewart & Stevenson has always demonstrated a willingness to work with HECO and help alleviate the problems you are having. We have gone far and above our normal responsibilities in the execution of our present contracts, and by making this latest offer we want to assure you that we want to be your partner "for a long time to come",

Sincerely yours,

Jay C. Manning

Director

International Sales & Marketing Gas Turbine Products Division

JCM:jt



STEWART & STEVENSON SERVICES, INC.

WORLD HEADQUARTERS

P.O. BOX 1637 HOUSTON, TEXAS 77251-1637 (713) 868-7700 TELEX: 704221 / 201445 CPW HOU FAX: (713) 868-7692

> CA-312 Docket No. 05-0315 Page 9 of 10

November 1, 1991

Hawaii Electric Light Company Inc. P. O. Box 1027 Hilo, Hawaii 96721-1027

Altention:

Mr. Warren H. W. Lee, PE

President

Subject:

Your Letter of Intent - Dated October 31, 1991

Kawaihae Combustion Turbine Number 4 S&S Letter dated September 26, 1991

Dear Mr. Lee,

I would like to thank you for your proposed letter of intent for the fourth unit to be located on the Big Island. However, inasmuch as there are slight differences from my original letter, I would like to propose the following changes for you to consider:

Item No. 1

We do not have a problem changing the delivery date to the site to be August 31, 1993. However, in order for us to meet the price level we have indicated to you, it is imperative that we use 1992 gas turbine engine pricing. In order to achieve 1992 engine pricing, we must purchase the engine in 1992. This is the reason for the 12/01/92 date for Payment No. 2 as stated in my letter of 9/26/91. Therefore, your option is to either increase the price of the unit by 3% to cover the engine increase or change the payment date back to 12/01/92.

Item No. 2

Certainly we will take into consideration any changes that HELCO would like to incorporate in this unit. However, in the event such changes may affect the price and delivery it is understood that both HELCO and Stewart & Stevenson will come to a satisfactory agreement considering any changes.

JCM20591.03

CA-312 Docket No. 05-0315 Page 10 of 10

Hawaii Electric Light Company Inc.
Attention: Mr. Warren H. W. Lee, PE
November 1, 1991
Page two

Mr. Lee, we certainly want to thank you for your continued support of Stewart & Stevenson in providing us with this opportunity.

I look forward to hearing from you soon on the above.

Sincerely yours,

Jay C. Manning

Director

International Sales & Marketing Gas Turbine Products Division

JCM:jt

cc: Neil Smith

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII

In the Matter of the Application of

HAWAII ELECTRIC LIGHT COMPANY, INC.

For Approval to Commit Funds in Excess of \$500,000 for the Purchase and Installation of Item PN-311, Keahole Combustion Turbine, CT-4.

DOCKET NO. 7048

COMMISSION OF DM/TO

CONSUMER ADVOCATE'S STATEMENT OF POSITION IN LIEU OF DIRECT TESTIMONY

and

CERTIFICATE OF SERVICE

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DEPT. OF CONSUMER AFFAIRS

2163

ROBERT A. MARKS Attorney General State of Hawaii

BRENDA MORRIS HOERNIG 3462 Deputy Attorney General 425 Queen Street Honolulu, Hawaii 96813 Telephone: 586-1180

Attorneys for the Consumer Advocate

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII

In the Matter of the Application of)
HAWAII ELECTRIC LIGHT COMPANY, INC.	DOCKET NO. 7048
For Approval to Commit Funds in Excess of \$500,000 for the Purchase and Installation of Item PN-311, Keahole Combustion Turbine, CT-4.))))

CONSUMER ADVOCATE'S STATEMENT OF POSITION IN LIEU OF DIRECT TESTIMONY

I. <u>INTRODUCTION</u>.

In this docket, Hawaii Electric Light Company, Inc.

(HELCO) asks the Commission to approve its plans to install a new 20 MW combustion turbine in West Hawaii. See gen. Application at 31. Following a review by its engineering section, the Consumer Advocate (CA) has no reason, at this point, to object to either HELCO's expressed need for additional generation, or to the type of generation unit HELCO has chosen to fulfill this need. However, and as will be discussed in detail below, the CA has grave concerns regarding the reasonableness of certain expenses which may be generated by some of the factors that are, or may ultimately be involved in HELCO's completion of its proposed generation expansion project.

Unfortunately, many of the facts necessary to present a

HELCO's original application filed on July 29, 1991 related HELCO's plans to install CT-4 at Kawaihae. HELCO subsequently filed an amended application on September 30, 1992 after it decided to relocate CT-4 to Keahole.

comprehensive picture of the CT-4 project have not fully evolved. The CA is therefore filing this Statement of Position in lieu of written, direct testimony. A dissertation of the CA's concerns and its plans for the remainder of its investigation of this docket are described below.

II. DISCUSSION.

A. HELCO's Decisions Regarding the Location of CT-4 may Result in the Inclusion of Unwarranted Expenses in HELCO's Rate Base.

In conjunction with its statutory duties to examine the reasonableness and necessity of HELCO's proposed addition to its generation capability, the CA is examining the prudence of the three sites HELCO has chosen to house the unit. HELCO originally selected the Kawaihae Harbor area as the site for CT-4. HELCO T-1 at 5. An alternative site at Puuanahulu was also considered. HELCO T-1 at 8. Due to a series of circumstances, HELCO ultimately changed the situs of CT-4 to Keahole, where its CT-2 unit is located. HELCO T-1 at 5-6.

HELCO estimates that the expenses attendant to selection of the now-abandoned Kawaihae site and the alternative Puuanahulu site total \$980,000. HELCO response to CA-IR-119. HELCO has also indicated in a somewhat oblique way that it intends to seek recovery of these expenses through rates². See

(continued...)

² CA-IR-120 and HELCO's response thereto are as follows:

CA-IR-120: State whether HECO/HELCO will attempt to recoup [the costs and fees associated with the Kawaihae and Puuanahulu site choices] in HELCO's next rate case.

HELCO response to CA-IR-120. Whether or not HELCO's ratepayers should bear the expenses related to the company's Kawaihae and Puuanahulu choices for the CT-4 site will depend on whether HELCO asks to recover these expenses and whether it was reasonable in selecting and developing data on these sites.

It is too early to tell whether HELCO will be forced to again relocate the CT-4 site due to community opposition to the current Keahole location of the project. Recent articles in West Hawaii Today a position paper submitted to the Commission by the Kona-Kohala Chamber of Commerce suggest that residents of the Kona area are strongly opposed to the proposed location of CT-4 at Keahole. See Exhibits 1, 2, 3 and 4 attached hereto. Strident local opposition to expansion at the Keahole site could, at the very least, result in delays in the anticipated November 1994 commercial operation date for the unit. The worst-case scenario in terms of securing additional generation as expeditiously as possible would occur if opponents of the Keahole site were able to force another relocation of the project. HELCO should reevaluate its decision to locate CT-4 at Keahole. Selection of another, more viable site at this time may result in less delay in securing needed generation expansion than if HELCO continues With the Keahole site only to ultimately be denied land use permits and to have to restart the project from that date.

If community opposition to the location of CT-4 at Keahole results in further delays in permitting and/or construction of the unit, additional costs to expedite installation of CT-4 may be generated. The Consumer Advocate is concerned that any expenses associated with an expedited construction and installation schedule be included in HELCO's rate base only if the delay that generated the expense was not caused by imprudence on HELCO's part.

The potential threat to the viability of the Keahole site is not sufficiently developed at this point to allow the CA to present the Commission with a well-supported opinion as to whether HELCO's planning and actions have been imprudent. This being the case, the CA asks the Commission to allow it to continue monitoring the situation through information requests and informal discussion with HELCO and/or HECO. In this way, the CA will have sufficient information to properly address the issue at the hearing of HELCO's next rate application.

B. Imprudent Decisions Regarding the Quality and Quantity of Data Submitted in Support of Air Quality Permits for CT-4 May Also Result in the Inclusion of Unwarranted Expenses in HELCO's Rate Base.

The CA is also looking into the reasonableness of the date on which HELCO plans to put its new combustion turbine into commercial operation. The reasonableness of this date is dependent, in part, on HELCO's ability to provide the Department of Health with timely and sufficient data in support of its applications for air and water quality permits. Unfortunately, according to HELCO's latest time-table for completion of the CT-4

project, many of the anticipated issuance dates for these permits will occur after the hearing of this docket is already completed.

According to exhibits HELCO-303, HELCO will violate its forecasted planning criteria for 1994 if CT-4 is not added. Beginning in April of 1994, HELCO's system capability, less units on maintenance, coupled with loss of the largest unit will not be sufficient to cover the forecasted peak of 153.0 MW3. See HELCO-303. It is interesting to note that HELCO has included 25 MW of geothermal energy from PGV and 10 MW of power from Hamakua Sugar in the calculation of its 1994 system capability. However, recent reports regarding PGV do not appear to indicate that the company will be providing firm capacity to the HELCO grid any time soon. Furthermore, Hamakua Sugar is scheduled to begin bankruptcy proceedings on December 23, 1992, so it is unlikely that it will continue to have a source of bagasse available to produce power for HELCO. As such, it may not be reasonable for HELCO to count on the 35 MW scheduled to be provided from these independent power producers within its calculation of the 1994 system capability.

The above-referenced problems make it critical that HELCO add CT-4, or some suitable generation source, to its system as soon as possible in order to minimize breaches of its 1994 planning criteria. As such, it is incumbent on HELCO to do everything within reason to expedite addition of the necessary

³ However, it should be noted that the violations of HELCO's 1994 planning criteria, without CT-4, are not expected to exceed 4 MW. See HELCO-302.

generation capacity is added to its system. Unfortunately, recent events suggest that HELCO may not be successful in accomplishing this task. As an example, according to HELCO T-4 at 15, HELCO planned to submit its application for an ATC/PSD permit to the Department of Health on December 15, 1992. It is the CA's understanding that HELCO did not file its application on December 15, and, instead, stated that it might be ready to file the application by the end of the year.

In addition, in support of an ATC/PSD permit application, the Department of Health (DOH) normally requires meteorological data to be gathered at the same height as the proposed CT stack over the nearest twelve-month period to the filing of the application. According to HELCO T-4 at 14-15, HELCO does not anticipate being granted a permit from the Department of Land and Natural Resources to build the tower from which this data will be collected until March of 1993.

If HELCO continues to postpone filing its application for the ATC/PSD permits and does not provide DOH with sufficient supporting data on a timely basis, it hardly seems likely that the permits will be issued in June of 1994, as HELCO has planned.

Since HELCO has not expressed a firm date on which it will file its application for the ATC/PSD permits for the CT-4 project, it is difficult to assess whether the ultimate issuance of the permits will be delayed as a result. However, if delays in providing DOH with timely or sufficient meteorological data result in a delay in the issuance of the air quality permits for

CT-4 and, consequently, in increased project expenses, the CA may argue that HELCO should not be allow to recover such additional expenses from its ratepayers. Since we cannot obtain the information necessary to satisfy this concern prior to the hearing of this docket, the CA again requests that the Commission keep the matter open to allow continuing discovery to ensure that all the relevant issues are adequately addressed.

III. CONCLUSION.

There is no solid basis at this point upon which the CA can posit its opinion regarding the reasonableness of many of the critical factors involved in the proposed CT-4 project. Some determinative evidence may be brought forth during the hearing of this docket. If not, the CA plans to continue with discovery through information requests, and address any lingering concerns during HELCO's next rate case. The CA therefore requests that the Commission accept this position statement in lieu of formal written testimony, allow it to cross-examine HELCO's and Waimana Enterprises' witnesses at the time of the hearing and pursue further discovery as necessary so that a complete assessment of the reasonableness and necessity of the CT-4 project can be

CA-313 Docket No. 05-0315 Page 9 of 17

presented to the Commission at the time of HELCO's next rate case.

DATED: Honolulu, Hawaii, December 18, 1992.

ROBERT A. MARKS Attorney General State of Hawaii

By:

BRENDA MORRIS HOERNIG Deputy Attorney General



KONA-KOHAL CHAMBER

CA-313 Docket No. 05-0315 Page 10 of 17

N

December 2, 1992

DK1. #7048 and

Mr. Warren Lee. President Hawaiian Electric Light Company, Inc. P. O. Box 1027 Hilo, HI 96721-1027

Subject: West Hawaii Energy Needs

Dear Mr. Lee.

The Kona-Kohala Chamber of Commerce is a 570+ member business organization serving West Hawaii.

At the November meeting of its Board of Directors, the Chamber adopted the attached position paper, in the broader sense as part of addressing the energy needs of West Hawaii, but more specifically to provide input to HELCO's plans to upgrade the generating capacity at its Keahole site.

The Chamber seeks reliable energy responsibly developed for West Hawaii.

As such, the thrust of our paper reaffirms past Chamber positions preferring Kawaihae as the site for a power plant to meet the future energy needs of West Hawaii. Rawaihae is chosen because of its industrial land use designation, as well as environmental and cost considerations due to the proximity to the harbor and thus the elimination of truck transportation of fuel to distant generating plants.

At the same time, to meet the short term energy needs of West Hawaii, we encourage the development of the Keeau site and more importantly, the implementation of an aggressive and meaningful conservation plan.

Lastly, the Chamber supports the phasing out of the Keahole site in its entirety recognizing its incompatibility with Keahole airport which is the primary entry point for tourists

EXHIBIT NO.

and the ongoing trend for commercial, residential, recreational, and educational development to continue north of Kailua towards Keahole and Kealakehe.

The Chamber believes that immediate implementation of these proposals will result in a long term reliable energy source that will have been developed responsibly in light of current community concerns.

The Chamber does not support the concept of scheduled rolling blackouts as a viable option to reduce energy requirements.

We trust that the above will provide you with our input, and look forward to working with you to address the future energy requirements of West Hawaii.

Sincerely,

Gordon N. Ogssaware President

XC: PUC DLNR

Councilpersons Schutte, Childs, and Rath

KKCC Planning Committee

KONA-KOHALA CHAMBER OF COMMERCE BOARD OF DIRECTORS NOVEMBER 19, 1992 MOVED, SECONDED AND PASSED

In order to solve the immediate generation shortfall on the Big Island in the most expeditious manner possible, as well as in the interest of good long term planning, the Kona-Kohala Chamber of Commerce feels that the following must be instituted:

- A) Kawaihae be chosen as the site for a power plant to produce power for West Hawaii with the capability of producing at least 50 megawatts
- B) Reeau be increased to a combined cycle plant which can produce at least 50 megawatts
- C) That the Keahole power generation units be phased out, the plant closed and dismantled
- D) That an agressive, meaningful conservation plan be instituted as soon as possible.

The reasons for the adoption of this position include:

- 1. The industrial nature of Kwhe lends itself to the uses and building design of a power plant
- 2. The transportation of fuel to the Keahole site (up to 94 trucks a day at full build out) would have a major impact on the Queen K.
- 3. The improvement of the Keahole site seem to be a short term solution (temporary?) for a permanent problem. The "solution" may not be in the best interests of West Hawaii
- 4. Keasu could be expanded to 50 mgts now to handle East Hawaii needs...with power being able to be transported across the island in times of emergency.
- 5. There are sesthetic concerns... Keahole is the entrance to Kona/Kohala for everyone who arrives by plane.
- 6. Most importantly, we need to put in place an agressive demand side management program, emphasizing conservation in the strongest terms possible.

belduou vilei said that pres refusing to iakua. They to jalk to us,

The stalemate stems (om negotiations in early November. The union and Hamakus essentially had reached an agreement, but then Feder came back with a

petition.

All the union wanted was basic assurances about housing, pension, vacation, medical benefits and severance pay, Lapenia said, "all basic issues that are of

Apenia sará socia officia nacia were on CA-313

Docket No. 05-0315 Page 13 of 17

> WEST HAV TODAY Wednesda December 1992



By DAN BREEDEN West Hawail Today

Plans to expand Keahole power plant and put a 104-foot smoke stack at the "gateway" to West Hawaii are ill-advised and should be reconsidered by Hawaii Electric Light Company Inc. officials, according to Hawaii residents.

The residents were speaking at a public meeting Tuesday evening in Kona where HELCO officials introduced the draft environmental impact statement for the expansion.

HELCO plans call for the 30.25-megawatt capacity plant at Keahole to be expanded to 86.25 megawatts in three

The enlarged plant is expected to be operational by 1997 and the first additional 20-megawatt turbine should be on line by

One of the primary concerns regarding the expansion is the construction of a 104-foot-tall stack. The structure would be visible from more than a mile away in most directions and would be particularly obtrusive for people driving toward Queen Kashumanu Highway from Keshole Air-

Ken One, president of the Community Organization for Educational Development. said putting the stack at the "gateway" to Kona would be "a major negative message" to tourists.

He said it would also likely create pollution at the University of Hawaii campus planned mauka of the Keahole plant.

Other individuals testifying also opposed the Keshole expansion.

In a prepared statement, Kelly Greenwell said new electrical generation facilities should be located in Kawaihae, "where it is appropriate."

County Councilmen Jim Rath said HELCO is pushing for the Keshole expansion because it will be a quick fix for poor decisions made by the company in the past.

"HELCO's bad management is not a secret," he said.



EXHIBIT No. 2 See KONA:

.. Kona power plant expansion is criticized

From Page 1A

Rath typified the situation as "trying to decide where on our face to put the wart." Locating the expansion at Keahole is essentially putting the wart on the nose, he said.

The 104-foot stack is smaller than a 190-foot one proposed in the EIS. The shorter stack will be adequate for dispersing particulate, according to HELCO officials.

Another problem with expanding the Keahole plant is that it will require enormous amounts of fuel to be trucked from Kawaihae Harbor, according to Rath. HELCO officials said the expanded plant will burn about 12 tankers full of fuel daily.

Rath said the community must push to have the expansion done at Kawaihae or Puuanahulu.

HELCO officials have studied building plants at both the Kohala sites but Keahole is the only location that would result in increased energy being available by 1994, according to Warren Lee, HELCO president.

Lee said the Puuanahulu site adjacent to the planned county landfili would result in at least an additional 18-month delay. And the Kawaihae site remains an unknown because Hawaiian Home Lands officials are first considering proposals from private energy companies owned by native Hawaiians.

The site would only be available to HELCO if no native-Hawaiian owned companies are interested or capable of building a power plant there, according to Les. Some individuals Tuesday said they are concerned that the Keshole expansion would be the first of several because the site would be more convenient than others for HELCO.

But Lee suggested that would not be the case.

"That's probably going to be the (final) expansion for Keshole at that site," Lee said.

Suggestions from the public included aggressively increasing energy conservation and considering alternative forms of generation.

Lee said voluntary conservation has helped avoid blackouts but would be insufficient to meet future energy needs and alternative generation would greatly increase the price of electricity.

The meeting continued at press

Big Islan

DHHL ac

Hawaii County tas state Department of E real property taxes.

The County Council Hawaiian lessees of herry taxes on their land

Former Mayor Lorr her final official duties

"I want to encourage this exemption by fill before Dec. 31, 1992, tionally, all lessees she lng. A copy of the hor same time as the exem

The tax exemptions 1993-94 tax year.

Akahi stili

HILO — An Akahi in the ongoing use perr with the golf course e allowed.

Former County Plans Akahi's Gene Lum prop no hotel. "I think that's

Susfuji also testified allowing golf courses in use permit. His compar by the council when it golf course about five m

Suefull testified that ity, which would determent, will be on as time goes on we muthe process." He added provides adequate safer

The hearing, requests will continue today. On will review the inform county Planning Board county to overturn the p

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Book borrowers do no drops will be open and d

Interisland

MONOTHE IT (A

...Hamakua says its closing operations

From Page 1A

Feder said the union is being unreasonable, and if the union leaders continue to refuse Hamakua's plan to cut personnel, wages and benefits, then "we'll just shut it down," Feder said, "It's up to them."

Feder said the closure could happen before the end of the year if the union will not bargain and agree to the reductions being requested.

Without movement from the union, we have no alternative," he said.

"I don't think there will be an immediate shutdown," Lapenia said. He added, however, he is being optimistic in that view.

Even if the union leaders and members agree to the 15 percent reduction in wages and benefits and give the company the right to terminate employees without regard to seniority, Hamakua will probably continue operations only until the crops in the ground are harvested.

Feder relicrated what he and others working to save the embattled company have said

work force.

Feder, the union and representatives from the Western Farm Credit Bank, the company's major creditor, presented their case to a U.S. Bankruptcy judge Tuesday, who granted a continuation until Dec. 23 to allow the organizations time to more fully work out a plan that will enable the company to slowly wind down over the next couple of years, Feder said.

Lapenia said the union will be negotiating directly with the bank and no longer with Feder from now on.

Feder said "an orderly winddown of sugar operations" is needed "so the value of the crops in the ground can be realized for everyone." If the union will not agree to an orderly wind down, then likely only the creditors will receive any value from the folding company, he said.

Lapenia said the union workers have already agreed to sacrifices and should not have to continue giving in to the company at the expense of themselves and their families.

Thau, have, had no, ween

Earlier this year, Hamakua attempted to sell off land for resort and residential development, which was to help it pay off some of the debt. That plan fell through.

Domingo said state and county officials have already begun discussing the need for a plan to encourage alternative industries for the area.

Domingo outlined a possible expansion and overhaul of the cattle production and alaughter industry already existing in his district.

"We could make Honokas a major center for producing and slaughtering cattle," he said, adding that first environmental issues surrounding the industry would need addressing. But it is an option, he said, although not the total answer to the problem.

Another option would be developing some of the land for golf courses and resort use.

Domingo atreased, however, that not all the land should be taken out of agriculture. "I would like to see conservation of part.

Opinion

Keahole expansion should go elsewhere

HELCO is facing an upbill battle in its efforts to expand generation capability in West Hawali at Keahole and Puuanahulu, facing community ire over the visual and aesthetic impacts that would result from the plans as now proposed.

HELCO is not bargaining from a position of strength and popularity. Rates have gone up and though it has been 149 days (at this writing) since the last blackout (except localized blackouts, according to HELCO President Warren Lee) public patience with the utility has not worn thin, it has worn out.

However, when the company moves to improve its power generation capability and delivery reliability, it also has run into a public relations nightmare.

The problem is simple. Increased urbanization in West Hawaii results in an increased need for power generation, and economy and reliability dictate the power be generated as close as possible to consumers. Current technology and economies of scale are limiting HELCO's options for power production to dual-train combined cycle systems of combustion turbines and heat recovery steam generators, according to Lee. These are large, unsightly and require tall stacks to carry away waste heat and particulate matter.

That visual hurdle is high enough. But when the proposed power plant expansion is immediately mauks of Keahole Airport, the visitor industry gateway to West Hawaii, that hurdle appears nearly insurmountable.

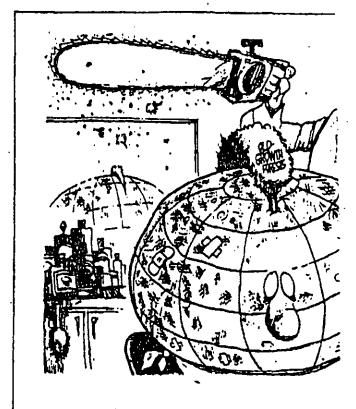
HELCO is proposing to construct a 104-foot-tail stack at the Keahole site. That stack is lower than the initially proposed 210-foot-tail stack and lower than the FAA-mandated 190-foot maximum height (because of airport proximity), however, based upon preliminary community response, even the lowest proposed height is too much and in the wrong location.

Additionally, HELCO is proposing expanded production, which would ultimately include as many as four 210-foot-tail stacks in the vicinity of Phuanahulu.

Because of the location of the Keahole generating station, it would be advisable for HELCO to re-evaluate its plans and focus expansion of its generating plants in a more appropriate location than the entrance to Keahole Airport. That location reflects poor planning, especially if we are truly interested in continuing to promote this region as a visitor destination. It would make more sense for HELCO to concentrate its expansion efforts at Puuanahulu, adjacent to the new landfill site, a far more appropriate location for such a highly visible industrial endeavor.

This conflict between the aesthetic concerns of the community and the need for urbanization and supporting infrastructure created by the community's attractive aesthetic qualities will not easily be resolved, but it will become increasingly common as this region grows.

-A West Hawali Today editorial.



Quality of life promis

Quality of life. It is a wondrous phrase. It says so much, yet is so incredibly nebulous, it says so were little

Those three words were spoken with great conviction Monday in Hilo by two men who will be in a position to effect certain meaning upon those words, Mayor Stephen Yamashiro and County Council Chairman Spencer Kalani Schutte.

I do not doubt the conviction of either man in his stated purpose to regard and safeguard the quality of life for residents. This noble-sounding quest, in reality because of its so very nebulous definitive nature, is Quixotic.

Yamashiro, in his inaugural address, told the assembled people at Hilo's Afook-Chinen Civic Auditorium that it was important



to keep a family hear

It is all this and m perhaps the best baro: change. Change is often means we have of regist quality of life. Schutte warmly on driving can Mamalshoa Highway Waimes town, someth change precludes from ethappening (intentionally) taiks about the improved services to the regi

CA-313 Docket No. 05-0315 Page 16 of 17

12--Hawaii Titbune - Herald, Wednesday, Decaraber 9, 1992

Helco plans major expansion at Keahole plant

needed, Helco says megawatts will be C) More than 200

By Dave Smith

ficials last night presented residents of Kona with plans for an expansion of the firm's Keahole Hawaii Electric Light Co. ofpower plant.

Helco has proposed expanding do the Keabole plant from its cure. Keabole capacity of 30 megawatts to 86 megawatts by 1997.

The utility's plans include in-

tallation of 20-megawatt com-

bustion turbine generators in Keabole but later determined 1994 and 1996, followed by de- that the smaller sack would be velopment of a 16-megawait, adequate. The plant currently hear-recovery generation until in has a 70-foot tall stack.

for the plant located along the a year. Among the stumbling blocks encountered by Helco last night was public opposition to a proposed 104 foot tall stracke stack One resident reportedly said allowing the stack to be built at the Keahole location, which he described as the "gateway" to Queen Kashumana Highway up-slope of the Keabole Airport.

allowing the stack to be built at fill now being developed by the the Keahofe location, which he county at Punanhulu about 20 described as the "gateway" to miles north of Kaiina.

Kona, would stad a negative Heloo officials said they are message to tourists arriving at moving ahead with plans to estimate nearly airport.

Heloo originally had proposed the Punanhulu plans cannot be constructing a 190-foot stack at brought into production in time

the firm's expany was located K in East Hawaii. Transmitting we power across the island results in in both an increased risk of our in ages, and a loss of up to 10 percent of the power during transmission, the company said. Heloo is also currently seeking approvals to install a temporary 190-foot tall sower to obtain footal weather information.

The tower would stand for about Helco is also proceeding with plans for a 168-megawan gener-ation plant near the county land-

According to Helco, a genera-tion capacity of 200 megawatts of electricity will be needed in West Hawaii within 20 years. If existing plans are carried out,

Earlier this year, Heloo said it power in West Hawaii of The ceeded to develop more power in West Hawaii by the six occeded to develop more power (Orange).

The courses in West Hawaii because.

The course in West Hawaii because in the final course in the falsa, about 70 percent of goodated through a new interest.

welop a power plant in Kawai. the have been complicated by st. the desire of the landowner, the tip Department of Hawaiian Home?

Lands, to have the plant dever. native Hawaiians.

Apother concern expressed last night concerned the 12 mockloads of fact oil that the fully expanded Keahole plant

would require daily from Hilo. The plant, which now includes six 2.75 megawai diesel generators and a trouble-plagued 13 megawatt combustion turbine, currently requires about four truckloads of fuel.

comental impact statement for the Keabole plant expansion, the state Department of Transporta-tion has proposed building a 27-mile long pipeline to carry a variety of fuels from Kawaihae that plan is dependent on an According to the draft envir-Harbor to Keahole, However, increased level of air traffir Keabole Airport to be econ-

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CERTIFICATE OF SERVICE

I hereby certify that I have this date forwarded copies of the foregoing document by means of hand-delivery and/or via U.S. Mail, postage prepaid and properly addressed, to the following:

WARREN H.W. LEE, PRESIDENT HAWAII ELECTRIC LIGHT COMPANY, INC. P.O. Box 1027 Hilo, Hawaii 96721-1027

BARRY M. UTSUMI, MANAGER RATE AND REGULATORY AFFAIRS DEPARTMENT HAWAIIAN ELECTRIC COMPANY, INC. P.O. Box 2750 Honolulu, Hawaii 96840-0001

ALBERT S.N. HEE, PRESIDENT WAIMANA ENTERPRISES, INC. Pauahi Tower, Suite 1520 1001 Bishop Street Honolulu, Hawaii 96813

THOMAS W. WILLIAMS, JR., ESQ. GOODSILL, ANDERSON, QUINN & STIFEL Alii Place, 18th Floor 1099 Alakea Street Honolulu, Hawaii 96813

DATED: Honolulu, Hawaii, December 18, 1992.

Brenda Morris Hoernig Deputy Attorney General

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DIRECT TESTIMONY AND EXHIBITS

OF

DAVID C. PARCELL

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: RATE OF RETURN

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1 DIRECT TESTIMONY OF DAVID C. PARCELL 2 I. INTRODUCTION. 3 Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS. 4 A. My name is David C. Parcell. I am Executive Vice President and Senior 5 Economist of Technical Associates, Inc. My business address is Suite 601, 6 1051 East Cary Street, Richmond, Virginia 23219. 7 8 YOUR **EDUCATION** Q. PLEASE SUMMARIZE BACKGROUND AND 9 PROFESSIONAL EXPERIENCE. 10 Α. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia 11 Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) 12 from Virginia Commonwealth University. I have been a consulting economist 13 with Technical Associates since 1970. I have provided cost of capital 14 testimony in public utility ratemaking proceedings dating back to 1972. In 15 connection with this, I have previously filed testimony and/or testified in over 16 375 utility proceedings before about 35 regulatory agencies in the United 17 States and Canada. 18 In connection with these proceedings, I filed written direct testimony in: 19 Maui Electric Company, Limited's ("MECO") last three rate proceedings 20 (i.e., Docket Nos. 94-0345, 96-0040 and 97-0346) wherein the cost of 21 capital issues in the first two cases were settled prior to the evidentiary

hearing and I was required to testify in the third case;

1		Hawaii Electric Light Company's ("HELCO") last two litigated rate
2		proceedings (Docket Nos. 94-0140 and 99-0207);
3		Hawaiian Electric Company, Inc.'s ("HECO") last rate proceeding
4		(i.e., Docket No. 04-0113 in which the cost of capital issues were
5		settled prior to hearing);
6		Young Brothers, Ltd.'s 1997 litigated rate proceeding (i.e., Docket)
7		No. 96-0483); and
8		The Gas Company's 2001 rate proceeding (i.e., Docket No. 00-0309 in
9		which the cost of capital issues were settled prior to hearing).
10		CA-400 provides a more complete description of my background and
11		experience.
12		
13	Q.	WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?
14	A.	I have been retained by the Division of Consumer Advocacy ("Consumer
15		Advocate" or "CA") to evaluate the cost of capital aspects of the current filing
16		of Hawaii Electric Light Company ("HELCO" or "Company"). I have performed
17		independent studies and will provide a recommendation of the current cost of
18		capital for HELCO. In addition, since HELCO is a subsidiary of HECO and,
19		ultimately, Hawaiian Electric Industries, Inc. ("HEI"), I have also evaluated
20		these entities in my analyses.

1	Q.	HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?
2	A.	Yes, I have prepared 16 exhibits, identified as CA-400 through CA-415.
3		These exhibits were prepared either by me or under my direction. The
4		information contained in these exhibits is correct to the best of my knowledge
5		and belief.

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II. RECOMMENDATIONS AND SUMMARY.

- 8 Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?
- 9 A. My overall cost of capital recommendations for HELCO are:

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ltem_	Percent	Cost Rate	Weighted Cost
Short-Term Debt	7.59%	5.00%	0.38%
Revenue Bonds	30.96%	5.90%	1.83%
Taxable Debt	6.48%	6.20%	0.40%
Hybrid Securities	2.41%	7.50%	0.18%
Preferred Stock	1.73%	8.37%	0.14%
Common Equity	50.83%	9.50%-10.25%	4.83%-5.21%
Total	100.00%	•	7.76%-8.14%
			7.95% (mid-point)

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HELCO's application requests a return on common equity of 11.25 percent and overall rate of return of 8.65 percent. I propose a return on common equity in the range of 9.5 percent to 10.25 percent, resulting in an overall rate of return in the range of 7.76 percent to 8.14 percent.

Q. PLEASE SUMMARIZE YOUR COST ANALYSES AND RELATED
 CONCLUSIONS FOR HELCO.
 A. This proceeding is concerned with HELCO's regulated electric utility

This proceeding is concerned with HELCO's regulated electric utility operations in Hawaii, relative to its 2006 test year. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. HELCO's proposed capital structure is its 2005 actual capital structure adjusted for expected changes in 2006. I also use the same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rates of debt and other fixed-cost capital. I have used the cost rates for long-term debt and other fixed-cost capital contained in HELCO's application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for HELCO. Each of these methodologies is applied to two groups of proxy electric utilities. These three methodologies and my findings are:

19	Methodology	Range
	Discounted Cash Flow	9.0-9.5% (9.25% mid-point)
20	Capital Asset Pricing Model	9.5-10.75% (10.125% mid-point)
21	Comparable Earnings	10.0%

Based upon these findings, I conclude that the cost of common equity for HELCO is within a broad range of 9.0 percent to 10.75 percent (9.9 percent

mid-point). For the purposes of my recommendation, I propose to use the middle portion of this range, or 9.5 percent to 10.25 percent.

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 7.76 percent to 8.14 percent (7.95 percent mid-point, which incorporates a cost of common equity of 9.8 percent). My specific cost of capital recommendation for HELCO is 7.95 percent.

A.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES.

- 9 Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT

 10 ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF

 11 RETURN FOR A REGULATED UTILITY?
 - Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The

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revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return (including income taxes).

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have not distinguished between the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is <u>Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia</u>, 262 U.S. 679 (1923). In this decision, the Court stated:

What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

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It is my understanding that the <u>Bluefield</u> decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time, as well as an underlying assumption that the utility be operated in a efficient manner.

The second decision is <u>Federal Power Comm'n v. Hope Natural Gas</u>

<u>Co.</u>, 320 U.S. 591 (1942). In that decision, the Court stated:

The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests From the investor or

company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The <u>Hope</u> case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the <u>Bluefield</u> and <u>Hope</u> decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that regulation is intended to act as a surrogate for competition.

- Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?
- A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is

the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

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- Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?
- 13 A. I have utilized three methodologies to determine HELCO's cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

- 17 IV. GENERAL ECONOMIC CONDITIONS.
- 18 Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN

 19 DETERMINING THE COSTS OF CAPITAL?
- 20 A. The costs of capital, for both fixed-cost (debt and preferred stock) components 21 and common equity, are determined in part by current and prospective 22 economic and financial conditions. At any given time, each of the following

factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of these factors is consistent with the Supreme Court's <u>Bluefield</u> decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Α.

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to-date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical

1 (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

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- Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS
 CYCLES AND THE MOST CURRENT CYCLE.
- 6 A. The three prior complete cycles and current cycle cover the following periods:

7	Business Cycle	Expansion Cycle	Contraction Period
	1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
8	1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
	1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
9	Current	Dec. 2001-Present	•

- 11 Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE
 12 CHANGING TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT
 13 ON COSTS OVER THIS BROAD PERIOD?
- 14 Α. Yes, I do. As I will describe below, the U.S. economy has enjoyed general 15 prosperity and stability over the period since the early 1980s. This period has 16 been characterized by longer economic expansions, relatively tame 17 contractions, relatively low and declining inflation, and declining interest rates 18 and other capital costs. The current business cycle began in late 2001, 19 following a somewhat modest recession in 2001. During the recession and 20 early in the succeeding expansion, the Federal Reserve lowered interest rates 21 (i.e., Fed Funds rate) eleven times in 2001 and twice in 2003 in an effort to 22 stimulate the economy.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND
 FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF
 CAPITAL.

CA-401 shows several sets of economic data. Page 1 contains general macroeconomic statistics while pages 2 and 3 contain financial market statistics. Page 1 of CA-401 shows that the U.S. economy is currently in the sixth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the reduction in the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates, as well as slower growth in corporate profits.

The rate of inflation is also shown on page 1 of CA-401. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.4 percent rate of inflation in 2005, which was similar to the level for 2004, was slightly higher than the most recent years, but was well below the levels of the past thirty years.

Α.

1 Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

Page 2 of CA-401 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005 and except for the prime rate and U.S. Treasury T-Bill 3-month rate, generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. In fact, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000. Even if rates were to increase moderately, they would still remain well below historical levels.

Α.

I Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICE	1	Q.	WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES
--	---	----	--

2 Α. Page 3 of CA-401 shows several series of common stock prices and ratios. 3 These rates indicate that share prices were basically stagnant during the high 4 inflation/high interest rate environment of the late 1970s and early 1980s. On 5 the other hand, the 1983-1991 business cycle and the most recent cycle have 6 witnessed a significant upward trend in stock prices. During the initial years of 7 the current expansion, however, stock prices were volatile and declined 8 substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high 10 levels.

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Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF **ECONOMIC AND FINANCIAL CONDITIONS?**

It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently will produce returns that are lower than was the case in prior years.

1	V	HELCO'S	OPERATIONS	AND	ileke
1	٧.	HELLOU 5	OPERATIONS.	ANU F	いつんつ

- 2 Q. PLEASE SUMMARIZE HELCO AND ITS OPERATIONS.
- 3 A. HELCO is an operating electric utility which is in the business of generating.
- 4 purchasing, transmitting, distributing, and selling electric energy. Its service
- 5 area is the island of Hawaii. HELCO (previously named Hilo Electric Light Co.
- 6 Ltd.) was acquired by HECO in 1970. The Company is a wholly-owned
- 7 subsidiary of HECO, which also owns MECO. Combined, these three
- 8 companies comprise the electric utility operations of HEI, which provide
- 9 electricity to 93 percent of Hawaii's residents.

- 11 Q. PLEASE BRIEFLY DESCRIBE HEI'S BUSINESS OPERATIONS.
- 12 A. HEI was incorporated in 1981 and, as part of a corporate restructuring in 1983.
- became the parent company of HECO, HELCO and MECO. HEI is a holding
- 14 company with subsidiaries engaged in the provision of electric energy
- 15 (i.e., HECO, HELCO, and MECO), financial services (i.e., American Savings
- 16 Bank, F.S.B.), and other businesses.

- 18 Q. WHAT ARE HEI'S BUSINESS SEGMENT RATIOS?
- 19 A. The major operations of HEI are shown on CA-402. The electric utility
- 20 percentages can be summarized as follows:

1				
		2003	2004	2005
2	Revenues	78.4%	80.6%	81.5%
	Income	66.8%	75.3%	57.1%
3	Capital Expenditures	90.2%	93.7%	97.3%
_	Assets	28.9%	29.6%	31.0%

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As this indicates, the electric utility operations have remained dominant in terms of revenues, operating income and capital expenditures. The "other" operations have remained small and, as a group, unprofitable.

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- 9 Q. PLEASE DESCRIBE THE NATURE OF HEI'S ELECTRIC ENERGY
 10 OPERATIONS.
- HECO constitutes HEI's electric energy operations, which are carried out through its own operations (i.e., the island of Oahu) and the operations of HELCO (i.e., the island of Hawaii) and MECO (i.e., the islands of Maui, Molokai, and Lanai), which it owns. As noted above, the electric energy operations account for about 80 percent of the revenues of HEI.

- 17 Q. HOW ARE HECO, HELCO AND MECO FINANCED?
- A. All of the common stock of HELCO and MECO are owned by HECO. HECO's common stock, in turn, is owned by HEI. The debt, preferred stock and hybrid securities capital of HELCO and MECO are arranged by HECO, although each subsidiary does have its own debt, preferred stock, and hybrid securities. However, the debt and hybrid securities of HELCO and MECO are guaranteed by HECO and the debt and hybrid securities ratings of each subsidiary are

1		derived from HECO's consolidated financial standing. As a result, HELCO
2		and MECO carry the same debt and hybrid security ratings as HECO. HELCO
3		and MECO have preferred stock ratings one "notch" below HECO since
4		HECO's preferred stock owners have a prior claim on all of HECO's assets to
5		the owners of HELCO's and MECO's preferred stock owners.
6		•
7	Q.	ARE THE FINANCING AND COSTS OF CAPITAL OF HELCO, MECO, AND
8		HECO INDEPENDENT OF HEI?
9	A.	No. The debt ratings of HECO (and, thus, HELCO and MECO) are partially
10		tied to the risks and operations of HEI. This has long been recognized by
11		Standard & Poor's, which noted in an October 11, 1993 CreditWeek):
2 3 4 5 6 7 18 19		Parent Hawaiian Electric Industries Inc.'s aggressive diversification activities in financial services, freight transportation, and real estate development (representing around 20% of total earnings) – have intensified consolidated financial risk. In view of parent debt financing, the utility is not fully insulated from higher-risk affiliates. [Emphasis added.]
20		Subsequent statements by Standard & Poor's indicate that this concern
21		persisted. In a November 1995 Global Sector Review), S&P noted:
22 23 24 25 26 27 28		HEI's diversification in financial services, freight transportation, real estate, and passive investments (25% of electric utility and savings bank net income) intensifies consolidated financial risk. In view of HEI debt, HECO is not fully insulated from higher-risk affiliates. [Emphasis added.] Standard & Poor's November 4, 1997 CreditWire:
29		HEI's ratings largely reflect the credit worthiness of HECO, adjusted for higher-risk non-utility units. HECO's ratings

reflect an average business profile and gradually improving financials. [Emphasis added.]

Standard & Poor's September 1999 Utility Credit Report:

HEI's aggressive diversification intensifies consolidated financial risk. Given parent debt, HECO is not fully insulated from higher risk non-utility affiliates. [Emphasis added.]

Even though HEI has, in recent years, divested itself of its more risky non-utility affiliates (e.g., international power), it remains that the utility operations are least risky. This is demonstrated in a July 9, 2004 Standard & Poor's Ratings Direct report:

Rating Methodology

The corporate credit rating of HEI reflects the credit fundamentals of HECO as well as the **higher-risk financial services operations** of American Savings Bank. However, Standard Poor's does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections and/or regulatory insulation. In HECO's case, Standard & Poor's believes that there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the Hawaii Public Utilities Commission (PUC) regarding the formation of the HEI's holding company structure, that insulate the utility from the parent's activities. The conditions imposed on HECO, and the PUC's ability, intent, and demonstrated willingness to protect HECO's creditworthiness provide Standard & Poor's with sufficient confidence to separate the corporate credit ratings of HEI and HECO by one notch. [Emphasis added.]

On a more recent basis, Standard & Poor's made the following statements in a May 31, 2006 Ratings Direct report on HEI:

The ratings on diversified holding company Hawaiian Electric Industries Inc. (HEI) are based on the consolidated credit profile of HEI's units, which include the electric utility, Hawaiian Electric Co., Inc. and its two utility subsidiaries (82% of core revenues and 61% of operating income as of Dec. 31, 2005) and the riskier financial services operations of American Savings Bank FSB (18% of core revenues and 39% of operating income). Standard & Poor's does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, an excellent fuel clause, and steady banking operations. The bank's consistent earnings are driven by net interest income from its low-cost deposit funding and low-risk earning-asset base. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, significant purchased power obligations, and support of the somewhat riskier banking businesses. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations. [Emphasis added]

This relationship is further demonstrated by the higher bond ratings which HELCO (and HECO/MECO) maintain relative to HEI. At the current time, HELCO's corporate credit rating is Baa1 by Moody's and BBB+ by Standard & Poor's, while HEI's corporate credit is rated lower at Baa2 by Moody's and BBB by Standard & Poor's (see CA-403). To my knowledge no changes in HELCO's bond ratings have occurred since this information request was prepared by HELCO.

- 1 Q. WHAT ARE THE CURRENT SECURITY RATINGS OF HELCO?
- 2 A. As shown in CA-403, page 2, the current ratings of HELCO are:

3		Moody's	S&P
4	First Mortgage Bonds ¹	A3	A-
-	Revenue Bonds	Baa1	BBB+
5	Preferred Stock	baa2	BBB-
6	Commercial Paper	P-2	A-2

- As this Exhibit indicates, HECO's most senior securities (i.e, revenue bonds),
- 8 presently carry "high" triple B ratings by the two major rating agencies.

10 Q. WHAT HAS BEEN THE TREND IN HELCO'S DEBT RATINGS?

- A. As CA-403, page 2 indicates, prior to 1990 HELCO's most prominent debt (i.e., revenue bonds) was rated A by each of the rating agencies. Moody's reduced HELCO's ratings in 1989, 1990, and 1991, while S&P also reduced the ratings in 1990. The ratings have remained the same since 1991.
- 16 Q. WHERE DOES HELCO RANK WITHIN THE 'BUSINESS POSITION'

 17 CATEGORIES THAT THE RATING AGENCIES HAVE ESTABLISHED?
- 18 A. Standard & Poor's has established a "business profile" system, ranging 19 from "1" (strong) to "10" (weak). HELCO has a business profile of "5." Since

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HECO redeemed all of its first mortgage bonds in 1999. These are the ratings at that time.

See response to CA-IR-205.

this business profile is in the middle of the range, it follows that the perceived business risk of companies in this category, including HELCO, are average.

4 Q. HOW IS THE REGULATORY CLIMATE IN HAWAII VIEWED?

A. Hawaii's regulatory climate is "Above Average," according to Value Line.³ It is noteworthy that only 10 of 50 states have "above average" Regulatory Climate designations.

It is also apparent that the regulatory process in Hawaii serves to minimize the risk of rate base disallowances. This is the case since the Commission's procedures provide for **four opportunities** to review major construction projects prior to their appearance in a rate proceeding. First, the Company annually submits a 5-year capital budget, which generally identifies generation and transmission projects due to the cost of these projects. Second, a 3-year financing plan is submitted when the Company seeks Commission approval to issue securities. Third, the resource planning process and related IRP hearings evaluate both planned construction and DSM programs on a five-year cycle with annual updates to the latest approved plan. Fourth, the Commission's G.O. #7 Standards provide for a submission of capital improvements application seeking Commission approval to commit

³ See Value Line Investment Survey of May 12, 2006, page 1774.

or expend funds for any single project over \$2,500,000.⁴ Commission approval (or failure to act within 90 days of filing)⁵ implies that the project will likely be included in rate base. From a practical standpoint, following Commission review at these steps the likelihood of rate base disapproval of the entire project cost is significantly reduced. Thus, the Company's business risk is also reduced. In addition, allowing HELCO to continue recovering the fuel costs associated with the change in the price of fuel through the Energy Cost Adjustment Clause also reduces the risk of the Company.

10 Q. HOW DO THE BOND RATINGS OF HELCO COMPARE TO OTHER 11 ELECTRIC UTILITIES?

A. As I indicated in a previous answer, HELCO has triple B bond ratings, which are investment grade (i.e., triple B or above). Of the 65 electric utilities and combination gas and electric utilities covered by AUS Utilities Reports, the following number of bond ratings currently exists:

		Moody's	S&P
17	Aa/AA	3	5
17	A/A	24	20
18	Baa/BBB	29	35
10	Ba/BB or Below	3	3
-	Not Rated	6	6

In Decision and Order No. 21002 filed on May 27, 2004 in Docket No. 03-0257, the Commission granted, among other things, a request by the electric utilities to increase the \$500,000 threshold for seeking Commission approval to commit funds for capital improvement projects to \$2,500,000.

Such action may result in the suspension of the application to allow the Commission and/or parties to the proceeding additional time to review the merits of the utility's proposal.

This comparison indicates that HELCO's ratings are in the most common rating category of electric utilities.

VI. CAPITAL STRUCTURE AND COST OF DEBT.

- Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL
 STRUCTURE IN A REGULATORY FRAMEWORK?
 - A. A utility's capital structure is important because the concept of rate base rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

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- 7 Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURES OF HELCO,
- 8 HECO AND HEI?
- 9 A. I have first examined the five year historic (2001-2005) capital structure ratios 10 of HELCO, HECO and HEI. Page 1 of CA-404 shows the capital structures of 11 HELCO. The common equity ratios of this company are shown below:

12		Including	Excluding
40		S-T Debt	S-T Debt
13	2001	50.0%	52.0%
4.4	2002	51.3%	53.7%
14	2003	52.4%	54.2%
4-	2004	51.9%	57.5%
15	2005	50.2%	57.8%

16 17

These generally indicate a recent, historic capital structure for HELCO of about 50 percent to 52 percent common equity.

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- 20 Q. HOW DO HELCO'S CAPITAL STRUCTURE RATIOS COMPARE TO THOSE 21 OF HECO?
- A. HECO's capital structure ratios are shown on page 2 of CA-404. The common equity ratios of HECO are shown below:

1		Including	Excluding
•		S-T Debt	S-T Debt
2	2001	50.3%	51.7%
•	2002	52.2%	52.4%
3	2003	52.9%	53.1%
	2004	53.7%	56.4%
4	2005	52.5%	56.6%

5 The common equity ratios of HECO are generally similar to those of HELCO.

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7 Q. WHAT ARE THE CAPITAL STRUCTURE RATIOS OF HEI?

8 A. These are shown on Page 3 of CA-404. The common equity ratios of HEI, on a consolidated basis, are summarized below:

10

		Including S-T Debt	Excluding S-T Debt
11	2001	40.2%	40.2%
	2002	43.8%	43.8%
12	2003	45.6%	45.6%
	2004	48.7%	50.2%
13	2005	48.0%	50.8%

14 These are somewhat lower than those of HELCO and HEI.

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16 Q. IS THERE ANYTHING UNIQUE ABOUT HELCO'S CAPITAL STRUCTURE?

17 A. Yes. A significant potion of HELCO's debt is revenue bonds, which are issued
18 in conjunction with the Department of Budget and Finance of the state of
19 Hawaii. This is a source of funding not generally available to many other
20 utilities and represents a favorable circumstance of HELCO.

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1	Q.	HOW DO THESE CAPITAL STR	UCTURES COMPARE TO THOSE OF
2		INVESTOR-OWNED ELECTRIC UT	ILITIES?
3	A.	CA-405 shows the common equi	ty ratios (including short-term debt in
4		capitalization) for the two groups o	f electric utilities covered by AUS Utility
5		Reports. These are:	
6			Combination Gas
7		Year Electric	And Electric
′		2001 42%	38%
8		2002 38%	36%
		2003 42% 2004 47%	38% 43%
9		2005 44%	47%
10			enerally lower than those of HELCO and
11		HECO over the 2001-2005 period.	
12			
13	Q.	WHAT CAPITAL STRUCTURE RAT	TOS HAS HELCO REQUESTED IN THIS
14		PROCEEDING?	
15	A.	Per HELCO-1801, the Company	requests use of the following capital
16		structure:	
17		Capital Item	Percent
4.0		Short-Term Debt	7.59%
18		Revenue Bonds	30.96%
19		Taxable Debt	6.48%
. •		Hybrid Securities	2.419/

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Hybrid Securities

Hybrid Securities

Common Equity

According to Company witness Tayne Sekimura, this capital structure was derived by taking the 2005 capital structure of the Company and adjusting

2.41%

1.73%

50.83%

1	it for expected changes in 2006. Ms. Sekimura states that this capital
2	structure has been derived using the same methodology employed by
3	HELCO, MECO and HECO in their recent rate proceedings.6

- 5 Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS IN THE MOST
 6 RECENT HELCO RATE PROCEEDINGS?
- 7 A. Yes, I have. Since Docket No. 7764, the Commission has used HELCO's
 8 projected average capital structures for the purpose of setting a rate of return
 9 for the Company. The dockets since this time incorporated the following
 10 capital structure ratios:

11 12	Capital Item	Docket No. 7764	Docket No. 96-0140	Docket No. 99-0207
13	Short-Term Debt	0.49%	5.21%	5.78%
14	Long-Term Debt	43.80%	38.74%	36.78%
15	Preferred Stock	7.62%	6.74%	7.75%
16	Common Equity	48.10%	49.30%	49.69%

17 18

The proposed ratios are similar to those requested in the current proceeding.

- 20 Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS
 21 PROCEEDING?
- 22 A. I will also employ the projected 2006 capital structure. I note, however, that
 23 HELCO may update its capital structure later in the proceeding. I may have
 24 further comments at that time.

⁶ See HELCO T-18, pages 2 and 3.

1	Q.	WHAT ARE THE COSTS OF FIXED-COST CAPITAL IN THE COMPANY'S
2		APPLICATION?
3	A.	The Company's Application (see HELCO-1801) contains the following cost
4		rates:
5 6		
_		Capital Item Percent
7 8		Short-Term Debt 5.00%
		Revenue Bonds 5.90%
9		Taxable Debt 6.20%
10		Hybrid Securities 7.50%
		Preferred Stock 8.37%
11		
12		It appears from the Application that these rates are calculated using the
13		same methodology as in prior proceedings I will also use these cost rates in
14		my analyses. The Company may also update these rates later in this
15		proceeding. As a result, I may have further comments at that time.
16		
17	Q.	CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME
18		DEGREE OF PRECISION AS THE COST OF DEBT AND OTHER FIXED
19		COST SECURITIES?

A. No. The cost rates of debt and other fixed-cost securities are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three

of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

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4 VII. SELECTION OF PROXY GROUPS.

- 5 Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR 6 HELCO?
- 7 A. HELCO is not a publicly traded company; rather, it is a subsidiary of HECO 8 and ultimately. HEI. As a result, it is not possible to conduct direct analyses of 9 the cost of common equity for HELCO. It is possible to conduct studies of 10 HEI's cost of equity; however, the diversified nature of this company's 11 operations indicate that it is not an adequate proxy, standing alone, for the 12 cost of equity for HELCO. I note that the Commission concurred with this 13 assessment in Decision and Order No. 16922 filed on April 6, 1999 in Docket 14 No. 97-0346 (In RE MECO), on page 40, wherein the Commission stated that 15 it did not consider HEI an appropriate proxy for MECO and did not consider 16 the HEI results. It is, however, useful to analyze groups of comparison or 17 "proxy" companies as a substitute for HELCO to determine its cost of common 18 equity. I have examined two such groups for comparison to HELCO.

1	Q.	HOW HAVE YOU SELECTED THE GROUPS OF COMPARISON
2		COMPANIES?
3	A.	My first group of comparison companies was selected using criteria similar to
4		that cited by the Commission in recent HELCO (Decision and Order No. 18365
5		dated February 8, 2001 in Docket No. 99-0207) and MECO (Decision and
6		Order No. 16922 dated April 6, 1999 in Docket No. 97-0346) Decisions. As I
7		interpret these Decisions, the Commission has noted that it is appropriate to
8		select comparison companies based upon the following criteria:
9		1. primarily an electric utility, with electric revenues providing most
10		of the company's total revenues;
11		2. publicly-traded common stock on New York Stock Exchange;
12		3. substantially regulated entity;
13		4. Value Line safety rating of 1 or 2;
14		5. first mortgage bonds rated within one rating increment of HECO;
15		6. if a holding company, have only one subsidiary;
16		7. common equity ratio in the 35 percent to 50 percent range; and,
17		8. be small (total market value of outstanding common equity within
18		\$0.45 billion to \$3.0 billion range). ⁷
19		The Commission has also identified, in some cases (e.g., [In RE
20		HELCO] Decision and Order No. 13762 dated February 10, 1995 in Docket

The Commission initially endorsed \$2.0 billion as the top end of the market value of common stock range. In Docket No. 97-0346, I proposed the market value criteria be expanded to \$3 billion. In its Decision and Order No. 16922, the Commission accepted my proxy group as "reasonable."

No. 7764 on page 53) a criterion of nuclear risk (i.e., no nuclear construction)
similar to HECO. The Commission further has noted (e.g., [In RE HECO]

Decision and Order No. 14412 dated December 11, 1995 in Docket No. 7766
on page 54) that in future cases these selection criteria may "be applied advisedly."

I have selected a group of six comparison companies based upon these criteria. Page 1 of CA-406 lists the six comparison companies and identifies the selection criteria. I note that I have included companies with a market cap up to \$5 million (reflecting growth in HEI's market cap) and equity ratios up to 60 percent (also reflecting an increase in the equity ratio of HEI and HELCO).

In addition to this group, I also selected a group of five electric companies using alternative selection criteria that I normally employ in electric utility cases. I have selected a group of eight companies based upon the following criteria:

- 1. Net utility plant of less than \$5 billion;
- 2. No nuclear generation;
- 3. Electric revenues of greater than 60 percent of total revenues;
- 4. Common equity ratio in the 40 percent to 55 percent range;
- 5. Standard & Poor's stock ranking of B or B+; and,
- 6. Moody's bond rating of A or Baa.
- These companies are identified on page 2 of CA-406.

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1	Q.	HOW DO THESE PROXY GROUPS COMPARE TO THE GROUPS THAT
2		HELCO WITNESS MORIN USES IN HIS COST OF CAPITAL ANALYSES?
3	A.	HELCO's cost of capital witness (Dr. Roger A. Morin) has not selected proxy
4		groups based upon any criteria specifically designed for comparison to
5		HELCO or the previously-cited Commission criteria. Rather, Dr. Morin has
6		used broad industry groups, such as Moody's Electric Utilities, vertically
7		integrated electric utilities, and natural gas utilities. In Section XIII of my
8		testimony, I will discuss the deficiencies with Dr. Morin's proxy group of
9		companies.
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11 VIII. DISCOUNTED CASH FLOW ANALYSIS.

- 12 Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE
 13 DISCOUNTED CASH FLOW MODEL?
- 14 A. The DCF model is one of the oldest, as well as the most commonly-used,
 15 models for estimating the cost of common equity for public utilities. The DCF
 16 model is based on the "dividend discount model" of financial theory, which
 17 maintains that the value (price) of any security or commodity is the discounted
 18 present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

 $K = \frac{D}{P} + g$ 1 2 where: K = discount rate (cost of capital) 3 P = current price 4 D = current dividend rate 5 G = constant rate of expected growth 6 This formula essentially recognizes that the return expected or required by 7 investors is comprised of two factors: the dividend yield (current income) and 8 expected growth in dividends (future income). 9 10 Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL. 11 For purposes of my analysis I have utilized the constant growth DCF model. A. 12 In doing so, I have combined the current dividend yield for each group of proxy 13 utility stocks described in the previous section with several indicators of 14 expected dividend growth. 15 16 Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF 17 **EQUATION?** 18 A. There are several methods that can be used for calculating the dividend yield 19 These methods generally differ in the manner in which the component. 20 dividend rate is employed; i.e., current versus future dividends or annual 21 versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a quarterly compounding variant, which is expressed as follows:

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$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (October-December 2006). The D_0 is the current annualized dividend rate for each proxy company.

Α.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

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A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

- 2001-2005 (5-year average) earnings retention, or fundamental growth (per Value Line);
- 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
- 2006, 2007, and 2009-2011 projections of earnings retention growth (per Value Line);
- 2003-2005 to 2009-2011 projections of EPS, DPS, and BVPS (per Value Line); and
- 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that

investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

6 Q. PLEASE DESCRIBE YOUR INITIAL DCF CALCULATIONS.

A. CA-407 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and range of low/high values. These results can be summarized as follows:

13		Mean	Median	High ⁸
14	Comparison Groups Commission Criteria	7.8%	8.0%	9.4%
15	Parcell Criteria	7.5%	7.2%	9.3%

I note that the individual DCF calculations shown on CA-407 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in CA-407 indicate average (mean and median) DCF cost rates of about 8 percent. The highest DCF rates (i.e., using the highest

⁸ Using only the highest growth rate.

1 growth rates only) are about 9½ percent for PUC criteria group and my criteria 2 group. 3 4 Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES? 5 Α. Based upon my analyses, I believe a broad range of 8 percent to 9½ percent 6 represents the current DCF cost of equity for HELCO. This cost of equity 7 recommendation is approximated by the upper portion of the average/mean 8 values, as well as the top DCF calculations for the proxy groups examined in 9 the previous analysis. I recommend a 9 percent to 9½ percent range for 10 HELCO, which focuses on the upper portion of the DCF range. 11 With respect to my DCF analysis, generally I have focused on the upper 12 portion of the DCF calculations because current financial conditions (low 13 interest rates and high market-to-book ratios for utilities) have the effect of 14 driving DCF results to low levels by historic standards. 15 16 IX. CAPITAL ASSET PRICING MODEL ANALYSIS. 17 Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF 18 THE CAPITAL ASSET PRICING MODEL. 19 Α. The CAPM is a version of the risk premium method. The CAPM describes 20 and measures the relationship between a security's investment risk and its

market rate of return. The CAPM was developed in the 1960s and 1970s as

1 an extension of modern portfolio theory (MPT), which studies the relationships 2 among risk, diversification, and expected returns. 3

- 4 Q. HOW IS THE CAPM DERIVED?
- 5 Α. The general form of the CAPM is:

$$K = R_f + \beta (R_m - R_f)$$

7 K = cost of equity where:

8 R_f = risk free rate

9 R_m = return on market

10 β = beta

11 R_m - R_f = market risk premium

12 As noted previously, the CAPM is a variant of the risk premium method. I 13 believe the CAPM is generally superior to the simple risk premium method 14 because the CAPM specifically recognizes the risk of a particular company or 15 industry (i.e., beta), whereas the simple risk premium method assumes the

same cost of equity for all companies exhibiting similar bond ratings.

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- 18 WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM Q. 19 YOUR CAPM ANALYSES?
- 20 Α. I have performed CAPM analyses for the same groups of proxy utilities 21 evaluated in my DCF analyses.

1 Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE? 2 A. The first term of the CAPM is the risk-free rate (R_t). The risk-free rate reflects 3 the level of return that can be achieved without accepting any risk. 4 In CAPM applications, the risk-free rate is generally recognized by 5 using the U.S. Treasury securities' rate. Two general types of U.S. Treasury 6 securities are often utilized as the R_f component - short-term U.S. Treasury 7 bills and long-term U.S. Treasury bonds. 8 I have performed CAPM calculations using the three-month average 9 yield (October-December 2006) for 20-year U.S. Treasury bonds. Over this 10 three-month period, these bonds had an average yield of 4.83 percent. 11 12 Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM? 13 Α. Beta is a measure of the relative volatility (and thus risk) of a particular stock in 14 relation to the overall market. Betas of less than 1 are considered less risky 15 than the market, whereas betas greater than 1 are more risky. Utility stocks 16 traditionally have had betas below 1. I utilized the most recent Value Line 17 betas for each company in the groups of proxy utilities. 18 19 Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT? 20 Α. The market risk premium component (R_m-R_f) represents the investor-expected

premium of common stocks over the risk-free rate, or government bonds. For

the purpose of estimating the market risk premium, I considered alternative

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measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. CA-408 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This exhibit also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

17		S&P 500	L-T Gov't Bonds	Risk Premium
18	Arithmetic	12.3%	5.8%	6.5%
10	Geometric	10.4%	5.5%	4.9%

I conclude from these total returns that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because

1		investors have access to both types of means and, presumably, both types are		
2		reflected in investment decisions and thus stock prices and cost of capital.		
3	•	Page 1 of CA-409 shows my CAPM calculations. The results are:		
4		Mean Median		
5		Comparison Groups PUC Criteria 10.2% 10.3%		
6		Parcell Criteria 10.3% 9.6%		
7		·		
8	Q.	HAVE YOU PERFORMED AN ALTERNATIVE SET OF CAPM		
9		CALCULATIONS?		
10	A.	Yes. I have performed an alternative set of CAPM calculations in order to		
11		address the Commission's preference for use of the risk premium from		
12		Ibbotson & Associates. I have developed such a risk premium by comparing		
13		the 1926-2005 total returns based on arithmetic returns, or 6.5 percent. I		
14		focus on the arithmetic return since the Commission has expressed a		
15		preference for use of the Ibbotson returns as the CAPM R _m .9		
16		Page 2 of CA-409 shows my CAPM calculations using this risk		
17		premium. The results are:		
18		_MeanMedian		
19		Comparison Groups PUC Criteria 10.8% 10.8%		
20 21		Parcell Criteria 10.8% 10.0%		

See, for example [In RE MECO], Decision and Order No. 16134 dated December 31, 1997 in Docket No. 96-0040 at page 28.

1	Q.	WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF
2		EQUITY?
3	A.	The CAPM results collectively indicate a cost of about 9.6 percent to
4		10.8 percent for the two groups of comparison utilities. I conclude that the
5		CAPM cost of equity for HELCO is within a range of 91/2 percent to
6		10¾ percent.
7		
8	X.	COMPARABLE EARNINGS ANALYSIS.
9	Q.	PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.
10	A.	The CE method is derived from the "corresponding risk" standard of the
11		Bluefield and Hope cases. This method is thus based upon the economic
12		concept of opportunity cost. As previously noted, the cost of capital is an
13		opportunity cost: the prospective return available to investors from alternative
14		investments of similar risk.
15		The CE method is designed to measure the returns expected to be
16		earned on the original cost book value of similar risk enterprises. Thus, this
17		method provides a direct measure of the fair return, because the CE method
18		translates into practice the competitive principle upon which regulation is
19		based.
20		The CE method normally examines the experienced and/or projected
21		returns on book common equity. The logic for examining returns on book
22		equity follows from the use of original cost rate base regulation for public

utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

A.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF HELCO'S COMMON EQUITY COST?

I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my CE analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns

do not represent the cost of capital. In addition, my CE analysis uses prospective returns and thus is not backward looking.

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Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2005 (i.e., last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2001-2005 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

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Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

17 A. CA-410 and CA-411 contain summaries of experienced returns on equity for 18 several groups of companies, while CA-412 presents a risk comparison of 19 utilities versus unregulated firms.

CA-410 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

CA-T-4 DOCKET NO. 05-0315 Page 45

1		Historic		Prospective	
•	Group	ROE	M/B	ROE	
2	Comparison Groups				
^	PUC Criteria	9.8-10.1%	136-139%	9.3-9.7%	
3	Parcell Criteria	9.3-11.3%	150-160%	8.2-9.7%	

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These results indicate that historic returns of 9.3-11.3 percent have been adequate to produce market-to-book ratios of 136-160 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2006, 2007, and 2009-2011 are within a range of 8.2 percent to 9.7 percent for the utility groups. These relate to 2005 market-to-book ratios of 152 percent or higher.

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Q.

HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

12 A. Yes. As an alternative, I also examined a group of largely unregulated firms. I 13 have examined the Standard & Poor's 500 Composite group, because this is a 14 well recognized group of firms that is widely utilized in the investment 15 community and the composite group is indicative of the competitive sector of 16 CA-411 presents the earned returns on equity and the economy. 17 market-to-book ratios for the S&P 500 group over the past fourteen years. As 18 this exhibit indicates, over the two stated periods this group's average earned 19 returns ranged from 12.2-14.7 percent with market-to-book ratios ranging 20 between 299 percent and 341 percent.

- 1 Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE 2 COST OF EQUITY FOR HELCO?
- 3 Α. The recent earnings of the proxy utility and S&P 500 groups can be utilized as 4 an indication of the level of return realized and expected in the regulated and 5 competitive sectors of the economy. In order to apply these returns to the cost 6 of equity for proxy utilities, however, it is necessary to compare the risk levels 7 of the electric utility industries with those of the competitive sector. I have 8 done this in CA-412, which compares several risk indicators for the S&P 500 9 group and the utility groups. The information in this exhibit indicates that the 10 S&P 500 group is slightly more risky than the utility proxy groups.

12 Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

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A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10 percent. Recent returns of 9.3-11.3 percent have resulted in market to-book ratios of 135 and greater. Prospective returns of 8.2-9.7 percent have been accompanied by market-to-book ratios of over 150 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective

1		returns of 10 percent reflect earnings levels that exceed the cost of equity for	
2		those regulated companies.	
3			
4	XI.	RETURN ON EQUITY RECOMMENDATION.	
5	Q.	PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY	
6		ANALYSES.	
7	A.	My three methodologies produce the following:	
8		Discounted Cash Flow 9.0-9.5% (9.2% mid-point)	
9		Capital Asset Pricing Model 9.5-10.75 (10.125% mid-point) Comparable Earnings 10.0%	
10		These result in a broad cost of equity range of 9.0 percent to	
2		10.75 percent. For the purpose of my recommendation, I propose to use the	
13		middle portion of this range. My overall conclusion from these results is thus	
14		an overall range of 9.5 percent to 10.25 percent. I recommend a cost of equity	
15		rate of 9.5 percent to 10.25 percent for HELCO.	
16			
17	XII.	TOTAL COST OF CAPITAL.	
8	Q.	WHAT IS THE TOTAL COST OF CAPITAL FOR HELCO?	
9	A.	CA-413 reflects the total cost of capital for the Company using the	
20		December 31, 2006 capital structure and costs of long-term debt, short-term	
21		debt, preferred stock, and my common equity cost recommendations. The	
22		resulting total cost of capital is a range of 7.76 percent to 8.14 percent, with a	

1		mid-point of 7.95 percent. I recommend that this 7.95 total cost of capital be
2		established for HELCO.
3		
4	Q.	DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE
5		COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS
6		FINANCIAL INTEGRITY?
7	A.	Yes, it does. CA-414 shows the pre-tax coverage that would result if HELCO
8		earned the mid-point of my cost of capital recommendation. As the results
9		indicate, the mid-point of my recommended range would produce a coverage
10		level within the benchmark range for a BBB rated utility. In addition, the debt
11		ratio (which reflects the capital structure as proposed by the Company) is
12		within that benchmark for an A rated utility.
13		
14	XIII.	COMMENTS ON COMPANY TESTIMONY.
15	Q.	HAVE YOU REVIEWED THE TESTIMONY OF HELCO WITNESS ROGER
16		MORIN?
17	A.	Yes, I have.
18		

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1	Q.	WHAT IS YOUR UNDERSTANDING OF DE	R. MORIN'S COST OF EQUITY
2		RECOMMENDATION FOR HELCO?	
3	A.	Dr. Morin is recommending an 11.25 perc	ent cost of common equity for
4		HELCO. This recommendation is based to	upon his implementation of the
5		following cost of equity models:	
6			Morin Conclusions
7		CAPM	
8		Traditional Empirical	11.6-12.1% 11.9-12.4%
9		Risk Premium	17.0 12.470
10		Historical Electric Utility Historical Natural Gas	10.3-10.8% 10.4-10.9%
11		Allowed Returns	10.7-11.0%
12		DCF	40.404
13		Electric Zacks Electric Value Line	10.1% 10.1%
10		Moody's Electric Zacks	9.8%
14		Moody's Electric Value Line Natural Gas Distribution Zacks	10.0% 9 .4%
15		Natural Gas Distribution Value Line	10.7%
16		Based upon these results, he concludes that	10.9 percent is the cost of equity
17		for an average risk electric utility. He recomn	nends an 11.25 percent return on
18		equity for HELCO, reflecting his perception the	nat HELCO faces above average
19		risks on its electric utility operations.	

1 Q. YOU PREVIOUSLY NOTED THAT DR. MORIN'S PROXY GROUPS WERE 2 NOT SELECTED USING CRITERIA CONSISTENT WITH PAST COMMISSION PRECEDENT. WHAT ARE THE IMPLICATIONS OF THIS? 3 4 Α. Over the past several rate proceedings involving HECO, HELCO, and MECO, 5 the Commission has provided some rather precise definitions of what it 6 considers to be appropriate proxy companies for use in determining the cost of 7 equity for these companies. My testimony, as indicated in a prior section, 8 follows these guidelines. Dr. Morin's analyses, on the other hand, do not. 9 Instead, he simply applies his cost of equity analyses to several broad groups 10 of utilities, not all of which are even electric utilities. None of his proxy groups 11 are selected based upon an analysis of the factors that make these companies 12 similar to HELCO. As a result, I believe that Dr. Morin's cost of equity 13 analyses do not properly address HELCO's risks and required returns. Use of 14 these broad proxy groups does not provide the required risk profiles and 15 specific recognition of HELCO's required returns.

16

17 Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S CAPM ANALYSES?

A. Dr. Morin performs CAPM analyses for a group of electric utilities (0.85 average beta). He combines a 0.85 beta with a 4.7-5.2 percent level cost of long-term (30-year) Treasury bonds and a 7.8 percent risk premium to get the following CAPM results:

1 K = RF + β (RP) = 4.7% + .85 (7.8%) = 11.3% 2 = 5.2% + .85 (7.8%) = 11.8%

- 3 He then adds a 0.3 percent flotation costs adjustment to this to get a
- 4 11.6 percent to 12.1 percent CAPM result.

5

- 6 Q. DO YOU AGREE WITH THIS CAPM ANALYSIS?
- 7 A. No, I do not.

8

- 9 Q. WITH WHICH COMPONENTS OF HIS CAPM ANALYSIS DO YOU
- 10 DISAGREE?
- 11 A. I disagree with the risk-free rate and risk premium components.

- 13 Q. WHY DO YOU DISAGREE WITH THE RISK FREE RATE?
- 14 A. Dr. Morin uses a risk-free rate range of 4.7-5.2 percent. He describes his
- risk-free rate as the level of U.S. Treasury 30-year long-bond yields prevailing
- in March 2006, as well as interest rate forecasts as of March, 2006. I have
- 17 two concerns with Dr. Morin's risk-free component. First, it is more
- appropriate to use 20-year Treasury bond yields, rather than 30-year yields,
- since 30-year bonds have not been issued on a continuous basis in recent
- 20 years. In addition, the Ibbotson series used in part by Dr. Morin to develop his
- 21 risk premium component used 20-year Treasury bond returns, not 30-year
- 22 bond returns.

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 Dr. Mo

The latest three-month average of 20-year Treasury bonds is 4.83 percent. The latest month's yield (i.e., December, 2006) is 4.78 percent. I believe that 4.83 percent more properly reflects the risk-free rate. I note that even 30-year Treasury bonds are less than the 5.2 percent rate used by Dr. Morin. Over the past three months, 30-year Treasury bonds had an average yield of 4.74 percent, while the average yield in December 2006 was 4.68 percent.

9 Q. WHAT IS YOUR DISAGREEMENT WITH DR. MORIN'S MARKET RISK

10 PREMIUM COMPONENT?

Α.

Dr. Morin's 7.8 percent risk premium is derived from two studies – the 1926-2004 Ibbotson Associates study showing a 7.2 percent differential between common stocks and the "income component" of Treasury bonds and a DCF analysis he performed for Value Line's aggregate stock market index and growth forecasts versus long-term Treasury bonds that produced a 8.3 percent differential. I disagree with both his studies.

I disagree with the first study since Dr. Morin improperly used "income returns" from the Ibbotson Associates study rather than "total returns." What Dr. Morin did was compare the differential between total returns for common stocks (i.e., dividends and capital gains) and only income returns for Treasury bonds. As such, he has ignored the capital gains component of the Treasury bonds return. As I indicated in my earlier testimony, the differential between

Dr. Morin acknowledges on page 24).

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19 Q.

PLEASE DESCRIBE DR. MORIN'S "EMPIRICAL" CAPM ANALYSIS.

20 Α.

This form of the CAPM assumes that beta for an industry understates the

Dr. Morin also employs what he describes as an "empirical" CAPM analysis.

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industry's volatility and thus risk and it is necessary to substitute the overall

Dr. Morin's second study relies upon his conclusion that the "expected return on the aggregate equity market" is 13.5 percent, which he derives by performing DCF analyses for the Value Line aggregate market. He combines a 1.6 percent dividend yield with a projected growth rate of 11.5 percent to arrive at a 13.1 percent return. He then adjusted the dividend yield by the growth rate to arrive at his 13.5 percent DCF cost, which he in turn compared to the 4.7-5.2 percent 30-year Treasury bond yields to arrive at a 7.8-8.3 percent risk premium.

total returns of common stocks and Treasury bonds is 6.6 percent (a figure

I do not believe this is an appropriate method by which to estimate the risk premium. Dr. Morin has not attempted to verify that the Value Line group of some 1,800 stocks is an appropriate standard for the risk premium (which is normally performed by using a smaller sample of large companies, such as the S&P 500). I note that historic returns for the S&P 500 have been 10.4 percent on a geometric basis and 12.3 percent on an arithmetic basis, both of which are less than the 13.5 percent conclusion of Dr. Morin.

market's beta (i.e., 1.0) for one-fourth of the industry's actual beta. Dr. Morin assumed that the appropriate beta in a CAPM analysis is a combination of the actual industry beta with a 75 percent weight and a beta of 1 with a 25 percent weight.

The use of an empirical CAPM overstates the cost of equity for companies with betas below that of the market. What the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market. This is not appropriate for HELCO or for other utilities.

I note that Dr. Morin's "empirical" CAPM is similar to a "zero beta" CAPM proposed by MECO witness Paul R. Moul in a 1999 proceeding before this Commission. In its decision in that proceeding (Docket No. 97-0346, In Re (MECO)), the Commission did not accept MECO's proposed CAPM.¹⁰

- Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF DR. MORIN'S RISK PREMIUM ANALYSIS.
- A. Dr. Morin performs three sets of risk premium analyses. Each of these involved the estimation of an equity risk premium over the 4.7-5.2 percent long-term Treasury bond yields used as the risk-free rate in his CAPM analyses. The three risk premiums he developed are:

See Decision and Order No. 16922, in Docket No. 97-0346, page 50.

1		 Historic risk premium for the electric utility industry;
2		 Historic risk premium for the gas distribution industry; and
3		Allowed risk premiums for the electric utility industry.
4		
5	Q.	PLEASE DESCRIBE DR. MORIN'S HISTORIC RISK PREMIUM FOR THE
6		ELECTRIC UTILITY INDUSTRY.
7	A.	Dr. Morin's historic risk premium for the electric utility industry involves an
8		examination of the total returns of 20-year Treasury bonds (capital
9		gains/losses plus interest) and Moody's Electric Utility Index (capital
10		gains/losses plus dividend yield) over the period 1932-2001. The average
11		historical difference between the electric utility returns and the Treasury bond
12		returns was 5.6. His historic risk premium for the electric utility industry simply
13		added the 4.7-5.2 percent Treasury bond yield to the 5.6 percent historic risk
14		premium to get a 10.3-10.8 percent result. To this he added 0.3 percent for
15		flotation cost.
16		
17	Q.	DO YOU AGREE WITH THIS METHODOLOGY FOR ESTIMATING THE
18		COST OF EQUITY FOR HELCO?
19	A.	No, I do not. Dr. Morin's historic risk premium of 5.6 percent is simply an
20		examination of historical events going back to 1932. He has made no
21		demonstration that economic and financial conditions in 2007 are similar to
22		those over the past eighty plus years. The use of such a methodology

implicitly assumes that the events of each of these years can have the same influences at the current time.

In addition, the risk premiums developed by Dr. Morin are generally dominated by the influence of capital gains in many years. For example, the year 1935 stock return of 77.49 percent reflects a 71.23 percent capital gain component. I do not believe it is proper to assign HELCO's cost of equity based upon a methodology which is dominated by stock market changes and bond market changes.

It is also apparent that the risk premium level has been very volatile over the 1932-2001 period. The highest risk premium was 71.96 percent in 1935 and the lowest was -37.34 percent in 1937. The averages by decade have also been quite different, as is shown on my CA-415. This indicates that the decade of the 1950's dominates the risk premium averages with a 14.06 percent premium. The decade of the 1990's, in contrast, shows a 0.02 percent risk premium. Dr. Morin's methodology weights these equally. It is doubtful that investors place equal weight on events in the 1930's and 1990's in making investment decisions, yet Dr. Morin's risk premium analysis implicitly assumes this is the case.

- 1 Q. PLEASE DESCRIBE DR. MORIN'S ANALYSIS OF ALLOWED RISK
 2 PREMIUMS FOR THE ELECTRIC UTILITY INDUSTRY.
- 3 Α. In this phase of his risk premium testimony, Dr. Morin compares the differential 4 between allowed returns on equity for electric utilities and long-term Treasury 5 bonds over the 1996-2005 period (i.e., last 10 years). The average spread 6 over this period was 5.5 percent, but Dr. Morin does not utilize this differential 7 as his risk premium. Instead, he performs regression analyses to track the 8 risk premium in terms of rising and falling interest rates. He then concludes 9 that a 6.1 percent risk premium is appropriate in conjunction with a 4.7 percent 10 Treasury bond yield and a 5.8 percent risk premium should be used with a 11 5.2 percent yield. This adjustment is not consistent with Dr. Morin's historic 12 risk premium analyses where he simply took the average risk premium over 13 the entire 1932-2001 period and applied it to the current level of Treasury 14 bond vields.

- 16 Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S DCF ANALYSES?
- Dr. Morin performs several sets of DCF analyses for three groups of electric utilities and natural gas utilities. In these analyses, he uses "spot" dividend yields for each company as of March 2006. For the growth rates, he used two indicators of growth Zacks 5-year EPS growth projections and Value Line projections of EPS growth.

The major problem with Dr. Morin's DCF analyses is the fact that he has used only one indicator of growth – projections of EPS growth. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth.

Dr. Morin's DCF analyses implicitly assume that investors rely exclusively on EPS projections in making investment decisions. This is a very dubious assumption and Dr. Morin has offered no evidence that it is correct. I note, for example, that Value Line – one of the sources of his growth rate estimates – contains many statistics, both of a historic and projected nature, for the benefit of investors who subscribe to this publication and presumably make investment decisions based at least in part from the information contained in Value Line. Yet, Dr. Morin would have us believe that Value Line subscribers and investors focus exclusively on one single number from this publication.

 I note in this regard that the DCF model is a "cash flow" model. The cash flow to investors in a DCF framework is dividends. Dr. Morin's DCF model, in contrast, does not even consider dividend growth rates.

- 19 Q. WHAT COMMENTS DO YOU HAVE CONCERNING DR. MORIN'S
 20 FLOTATION COST ADJUSTMENT?
- 21 A. Dr. Morin increases each of his cost of equity estimates by 30 basis points as 22 a flotation cost adjustment. There is no need to make a flotation adjustment,

as Dr. Morin recommends. A utility should only be allowed to recover from ratepayers its actual, quantifiable levels of issuance costs. Neither Dr. Morin nor HELCO has made any demonstration that the company has incurred any issuance costs. In addition, as my CA-410 reflects, my two proxy groups have 2005 market-to-book ratios of over 150 percent. To make a market-to-book adjustment for companies whose market-to-book ratio already exceeds 150 percent is unnecessary and inappropriate, since any common stock issuance would actually increase the book value of existing stockholders' stock.

Q. DR. MORIN MAINTAINS (HELCO T-17, PAGE 66) THAT HELCO'S SIZE IS A RISK FACTOR WHICH MUST BE ADDRESSED IN ASSESSING ITS RISK AND COST OF EQUITY. DO YOU AGREE WITH THIS PROPOSITION?
A. No, I do not. HELCO's securities are not rated and priced (i.e., interest rates) based upon a presumption that it is a "stand alone" entity. As I have indicated previously, HELCO's debt is guaranteed by HECO and carries the same ratings as HECO. Clearly, it is the consolidated operations of HECO (i.e., HECO, HELCO and MECO) that are evaluated by the capital markets. As a result, it is the size of HECO, on a consolidated basis, which is the relevant size from a risk standpoint. From a practical standpoint, HECO has

1		the ability to merge HELCO and MECO,11 thus eliminating any perceived size
2		risk factor.
3		
4	Q.	IN SOME PAST HECO, HELCO AND MECO PROCEEDINGS, THE
5		COMMISSION HAS MADE AN ADJUSTMENT ABOVE THE COST OF
6		EQUITY FOR COMPARISON ELECTRIC UTILITIES. DO YOU HAVE ANY
7		COMMENTS ON THIS?
8	A.	Yes, I do. The Commission has, in some past cases (e.g., Docket
9		No. 99-0207 for HELCO and Docket No. 97-0346 for MECO) added an
10		adjustment of 50 basis points to the cost of equity for comparison companies.
11		The Commission's decisions in these proceedings cited higher business risk
12		(higher operating ratio, lower quality of earnings, and weak level of internally
13		generated funds for construction), current national and local economic
14		conditions, and HECO's minimal investment grade bond rating as matters of
15		concern.
16		HELCO has requested a 35 basis point adjustment in this proceeding,
17		based upon Dr. Morin's conclusions that HELCO is more risky than his
18		Comparison groups.

comparison groups.

It is my understanding there are some legal reasons that require HELCO and MECO to remain separate entities. However, this does not provide a justification for evaluation of HELCO's financial risk on a stand-alone basis.

1 Q. DO YOU AGREE THAT THIS TYPE OF ADJUSTMENT IS WARRANTED?

2 A. No. I do not believe that current circumstances warrant an upward adjustment to the cost of equity for the comparison groups.

It is important to review the history of HECO's cost of equity adjustments. To the best of my knowledge, based upon a review of Commission decisions, the relevant Commission decisions dealing with this issue were:

Company	Docket No.	Date	Adjustment
MECO	7000	Aug. 5, 1994	115 basis points
HECO	7700	Dec. 28,1994	115 basis points
HELCO	7764	Feb. 10, 1995	110 basis points
HECO	7766	Dec. 11, 1995	90 basis points
HELCO	94-0140	Apr. 2, 1997	50 basis points
MECO	97-0346	Apr. 6, 1999	50 basis points
HELCO	99-0207	Feb. 8, 2001	50 basis points

As this indicates, the impetus for the adjustments occurred during the 1993-1994 period, as reflected in Commission orders in 1994-1995. Not coincidentally, this was also the time period during which HECO, MECO and HELCO were experiencing downgrades of their securities. I am also aware that, during this time period, the Commission's final rate case decisions were awarded at a slower pace.

In summary, the circumstances that HELCO presently encounters, both from the regulatory and financial standpoints, are much improved in comparison to the situation in the 1990s when the Commission first made an upward adjustment to HELCO's cost of equity. As stated elsewhere in my

testimony, HELCO's financial status has improved. The Commission's response time for rate cases has improved and, in fact, the Hawaii Commission is one of a few U.S. Commissions to have an "above average" rating by Value Line. I note that even HELCO's own perceptions of its relative risks have reflected a decline as the request of 0.35 percent upward adjustment in this case is lower than any previous Commission award.

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- 8 Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?
- 9 A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE DAVID C. PARCELL, MBA, CRRA EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University,
	(Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University,
	(Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical
	Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic
	Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics Beta Gamma Sigma - National Scholastic Honor Society of Business Administration Alpha Iota Delta - National Decision Sciences Honorary Society Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

<u>Financial Economics</u> -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia

State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

<u>Utility Economics</u> -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

<u>Insurance Economics</u> -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

<u>Special Studies</u> -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

<u>Franchise</u>, <u>Merger & Anti-Trust Economics</u> -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

<u>Transportation Economics</u> -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

<u>Economic Loss Analyses</u> -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony

has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts
Board of Directors 1992-2000

Board of Directors 1992-2000 Secretary/Treasurer 1994-1998 President 1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,

Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

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<u>The Cost of Capital - A Practitioners' Guide</u>, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), <u>Journal of Management and Business Consulting</u>, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), <u>Journal of Management and Business</u> Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), <u>University of Richmond Law Review</u>, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", <u>University of Richmond Law Review</u>, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", <u>Virginia Social Science Journal</u>, Vol. 24, 1989

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"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, <u>Journal of Managerial Issues</u>, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

	REAL GDP	IND PROD	UNEMP		
YEAR	GROWTH	GROWTH	RATE	CPI	PPI
		1975	- 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
				12.4%	
1980	-0.2%	-1.9%	7.0%		11.8%
1981 1982	1.8% -2.1%	1.9% -4.4%	7.5% 9.5%	8.9% 3.8%	7.1% 3.6%
1002	- 6. 170			3.070	0.070
		1983	- 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992	- 2001 Cycle		
			•		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000 2001	3.7%. 0.8%	4.5% -3.5%	4.0% 4.7%	3.4% 1.6%	3.6% -1.6%
2001	0.076			1.076	-1.076
		Cur	rent Cycle		
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	3.2%	3.2%	5.1%	3.4%	5.4%
2004					
1st Qtr.	3.9%	2.8%	5.6%	5.2%	5.2%
nd Qtr.	4.0%	4.9%	5.6%	4.4%	4.4%
Brd Qtr.	3.1%	4.6%	5.4%	0.8%	0.8%
th Qtr.	2.6%	4.3%	5.4%	3.6%	7.2%
			.	2.270	
2005 1st Qtr.	3.4%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.2%	1.6%
Brd Qtr.	4.2%	2.7%	5.0%	9.6%	10.8%
sta Qtr. Ith Qtr.	1.8%	2.7% 3.1%	5.0% 4.9%	9.0% -2.0%	4.0%
		5		570	,
2006	E 664	9.40/	4 70/	4 002	0.007
st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
Ind Qtr. Brd Qtr.	2.6%	4.3%	4.6%	4.8%	6.4%
	2.0%	5.1%	4.7%	0.4%	-4.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

	PRIME	US TREAS T BILLS	US TREAS T BONDS	BONDS	BONDS	BONDS	BOND
YEAR	RATE	3 MONTH	10 YEAR	Ass	<u> Aa</u>	A	Bea
			1975 - 198	-			
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.969
1976	6.84% 6.83%	4.99% 5.27%	7.61% 7.42%	8.63% 8.19%	5.92% 5.43%	9.29% 8.61%	9 82%
1977 1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9 62%
1979	12.67%	10.04%	9.44%	9.85%	10.22%	10.49%	10.969
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.959
1981	18.89%	14.03%	13.93%	14.54%	15.30%	15,95%	16.609
1982	14.88%	10 69%	13.00%	14.22%	14.79%	15 86%	16.451
			1983 - 199	1 Cycle			
1983	10.79%	8.63%	11.10%	12.52%	12.83% 13.66%	13 66 %	14.201
1984 1985	12.04% 9.93%	9.58% 7.48%	12.44% 10.62%	12.72% 11.68%	12.08%	14.03% 12.47%	14,531
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.009
1987	8.21%	5 82%	8.39%	9.52%	9.77%	10.10%	10.53
1988	9.32%	6.69%	8.85%	10.05%	10 26%	10.49%	11.009
1989	10.87%	8.12%	8 49%	9.32%	9 56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9 65%	9.86%	10.069
1991	8.46%	5.42%	7.86%	8.85%	9 09%	9.38%	9.55%
			1992 - 200	1 Cycle			
1992	6.25%	3,45%	7.01%	8.19%	8.55%	8 69%	8.86%
1993	6.00%	3.02%	5.67%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	B 63%
1995	8 83% 8.27%	5.51% 5.02%	6.57% 6.44%	7.68% 7.48%	7,77 % 7,57 %	7.59%	8 29% 6.16%
1996 1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.75% 7.50%	7.95%
1998	8.35%	4.81%	5.26%	8.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.52%	7.88%
2000	9 23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current C	ycle			
2002	4.67%	1.62%	4.61%		7,19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		8.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	8.16%	6.40%
2005	6.19%	3.15%	4.29%		5.44%	5.65%	5.93%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	8.15%	8.47%
Feb	4.00%	0 92%	4.08%		6.10%	8.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.48%
May	4.00%	1.04%	4.72%		8 66%	6 62%	6.75%
June	4.00%	1.27%	4.73% 4.50%		6.30% 6.09%	6.46%	6.84% 6.67%
July	4.25% 4.50%	1,35% 1,48%	4.25%		5.95%	6.27% 6.14%	6.45%
Aug Sept	4.75%	1.85%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17% 6.17%
Nov	5 00%	2.06%	4.19%		5.79%	5.97%	6.16¥
Dec	5 25%	2.20%	4.23%		5.76%	5.92%	6.10%
2005 Jan	5 25%	2.32%	4,22%		5.68%	5.78%	5.95%
Jan Feb	5 50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	8.019
Apr	5.75%	2.79%	4.34%		5 56%	5.64%	5.95%
Mary	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5 05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.63%
Oct	8.75%	3.70%	4 46%		5.50%	5.79%	8.08%
Nov	7.00%	3.90%	4.54% 4.47%		5.59% 5.55%	5.88%	6.19%
Dec	7.25%	3.89%	4.4/70		3.0376	5 80%	6.149
2006 Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Jan Feb	7.50%	4.41%	4.57%		5.55%	5.82%	8.119
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.269
	7.75%	4.59%	4.99%		6.02%	6.29%	8.54%
	8.00%	4.72%	5.11%		6.18%	6.42%	6.59%
Apr May					8.16%	6.40%	6.61%
Apr	8.25%	4.79%	5.11%				
Apr May June	8.25%	4.96%	5 09%		6.13%	6.37%	6.61%
Apr May June July Aug	8.25% 8.25%	4.96% 4.98%	5 09% 4.88%		6.13% 5.97%	6.37% 6.20%	6.61% 6.43%
Apr May June July	8.25%	4.96%	5 09%		6.13%	6.37%	6.81% 6.43% 6.26% 6.24%

STOCK PRICE INDICATORS

	S&P	Nasdaq		S&P	S&P
YEAR	Composite	Composite	DJIA	D/P	E/P
		1975 - 198	2 Cycle		
1975			802.49	4.31%	9,15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.799
1978			820.23	5,28%	12.039
1979			844.40	5.47%	13.469
1980			891.41	5.26%	12.669
1981			932.92	5.20%	11.969
1982			884.36	5.81%	11.604
		1983 - 199	1 Cycle		
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.029
1985			1,328.23	4.25%	8.129
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.489
1988			2,060.82	3.64%	8.019
1989	322.84		2,508.91	3.45%	7.419
1990	334.59		2,678.94	3.61%	6.479
1991	376.18	491.69	2,929.33	3.24%	4.799
		1992 - 200	1 Cycle		
1992	415.74	599.26	3,284.29	2.99%	4.229
1993	451.21	715.16	3,522.06	2.78%	4.469
1994	460.42	751.65	3,793.77	2.82%	5.839
1995	541.72	925.19	4,493.76	2.56%	6.099
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1,77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	
2000			10,734.90	1.15%	3.17%
2001	1,427.22 1,194.18	3,783.67 2,035.00	10,189.13	1.32%	2.95%
		Current	Cycle		
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.849
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.409
2002	.,	.,	•		
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.		1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	1,068.45			1.76%	
4th Qtr.	894.65 887.91	1,308.17 1,346.07	8,487.59 8,400.17	1.79%	3.689 3.149
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.879
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.389
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.629
2nd Qtr.	1,122.87	1,984.13	10,289.04	1,71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.119
2nd Qtr.	1,181.85	2,012.24	10,382.35	1.85%	5.329
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.429
4th Qtr.	1,230.47	2,178.67	10,615.78	1.88%	5.609
2006					
	1 202 04	2,287.97	10,996.04	1.85%	5.61%
1st Qtr.	1,283.04	2,207.07	,		
1st Qtr. 2nd Qtr.	1,281.77	2,240.48	11,188.84	1.90%	5.88%

Source: Council of Economic Advisors, Economic Indicators, various Issues.

HAWAIIAN ELECTRIC INDUSTRIES, INC. SEGMENT FINANCIAL INFORMATION 2003 - 2005 (\$000)

Segment	Revenues	Income From Continuing Operations	Capital Expenditures	Assets
		2003		
		2003		
Electric Utility	\$1,396,685	\$78,911	\$146,964	\$2,687,798.0
	78.4%	66.8%	90.2%	28.9%
Bank	\$371,320	\$56,261	\$15,798	\$6,515,208.0
	20.8%	47.7%	9.7%	70.0%
Other	\$13,311	-\$17,124	\$129	\$104,694.0
	0.7%	-14.5%	0.1%	1.1%
Hawaiian Electric Industries, Inc. (Consolidated)	\$1,781,316	\$118,048	\$162,891	\$9,307,700.0
		2004		
Electric Utility	\$1,550,671	\$81,177	\$201,236	\$2,879,615.0
	80.6%	75.3%	93.7%	29.6%
Bank	\$364,284	\$41,062	\$13,085	\$6,766,505.0
	18.9%	38.1%	6.1%	69.6%
Other	\$9,102	-\$14,500	\$333	\$73,137.0
	0.5%	-13.5%	0.2%	0.8%
Hawaiian Electric Industries, Inc. (Consolidated)	\$1,924,057	\$107,739	\$214,654	\$9,719,257.0
		2005		
Electric Utility	\$1,806,384	\$72,802	\$217,609	\$3,081,460.0
	81.5%	57.1%	97.3%	31.0%
Bank	\$387,910	\$64,883	\$5,731	\$6,835,335.0
	17.5%	50.9%	2.6%	68.7%
Other	\$21,270	-\$10,241	\$335	\$34,782.0
	1.0%	-8.0%	0.1%	0.3%
Hawaiian Electric Industries, Inc. (Consolidated)	\$2,215,564	\$127,444	\$223,675	\$9,951,577.0

Source: Response to CA-IR-208.

BOND RATINGS

	HE	HECO		MECO		HELCO		<u> </u>
Date	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
Corporate Credit Rating	Baa1	BBB+						BBB
First Mortgage Bonds	А3	A-						
Revenue Bonds (uninsured)	Baa1	BBB+	Baa1	BBB+	Baa1 .	BBB+		
Medium Term Notes	Baa1	BBB+	Baa1	BBB+	Baa1	BBB+	Baa2	BBB

Note: HECO, MECO, and HELCO no longer have any first mortgage bonds, medium term notes, or uninsured revenue bonds outstanding.

Source: Response to CA-IR-210.

HISTORY OF SECURITY RATINGS HAWAIIAN ELECTRIC COMPANY

	First Mortga	age Bonds	Revenue	Bonds	Preferred Stock		Commercial F	
Year	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
 1974	Α	Α	· A		a	Α	P-1	
1975	A	A	A		а	A	P-1	
1976	A	A	A		а	Α	P-1	
1977	Α	Α	Α		а	Α	P-1	A-1
1978	Α	A	A		а	Α	P-1	A-1
1979	Α	Α	Α		а	Α	P-1	A-1
1980	Α	Α	Α		а	Α	P-1	A-1
1981	Α	Α	Α		а	Α	P-1	A-1
1982	A1	A+	A2	Α	a1	A+	P-1	A-1
1983	A1	A+	A2	A	a1	A+	P-1	A-1
1984	A1	A+	A2	Ä	a1	A+	P-1	A-1+
1985	A1	A+	A2	Ä	a1	A+	P-1	A-1+
1986	Aa3	A+	A1	Ä	aa3	A+	P-1	A-1+
1987	Aa3	A	A1	Ä-	aa3	Α-	P-1	A-1
1988	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1989	A1	A	A2	A-	a1	A-	P-1	A-1
1990	A2	A-	A3	BBB+	a2	BBB+	P-1	A-2
1991	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1992	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1993	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1994	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1995	A3	BBB+	Baa1	BBB+	baa1	BB8+	P-2	A-2
1996	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1997	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1998	A3	A-	Baa1	BBB+	baa1	BBB-	P-2	A-2
1999		tgage bonds	Baa1	BBB+	baa1	BBB-	P-2	A-2
2000	redeemed i		Baa1	BBB+	baa1	BBB-	P-2	A-2
2001			Baa1	BBB+	baa2	BBB-	P-2	A-2
2002			Baa1	BBB+	baa2	BBB-	P-2	A-2
2003			Baa1	BBB+	baa2	BBB-	P-2	A-2
2004			Baa1	BBB+	baa2	BBB-	P-2	A-2
2005			Baa1	BBB+	baa2	BBB-	P-2	A-2
2006			Baa1	BBB+	baa2	BBB-	P-2	A-2

HAWAII ELECTRIC LIGHT COMPANY CAPITAL STRUCTURE RATIOS 2001 - 2005 (\$000)

YEAR	COMMON	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2001	\$165,655	\$27,000	\$125,962	\$12,600
	50.0%	8.2%	38.0%	3.8%
	52.0%	8.5%	39.5%	
2002	\$171,404	\$27,000	\$120,993	\$14,900
	51.3%	8.1%	36.2%	4.5%
	53.7%	8.5%	37.9%	
2003	\$174,639	\$27,000	\$120,867	\$10,800
	52.4%	8.1%	36.3%	3.2%
	54.2%	8.4%	37.5%	
2004	\$186,505	\$17,000	\$120,908	\$34,850
	51.9%	4.7%	33.7%	9.7%
	57.5%	5.2%	37.3%	
2005	\$189,407	\$17,000	\$121,009	\$49,700
	50.2%	4.5%	32.1%	13.2%
	57.8%	5.2%	37.0%	· - · - · -

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-207.

HAWAIIAN ELECTRIC COMPANY (CONSOLIDATED) CAPITAL STRUCTURE RATIOS 2001 - 2005 (\$000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2001	\$877,154	\$134,293	\$685,269	\$48,297
2001	50.3%	7.7%	39.3%	2.8%
	51.7%	7.9%	40.4%	2.070
2002	\$923,256	\$134,293	\$705,270	\$5,600
	52.2%	7.6%	39.9%	0.3%
	52.4%	7.6%	40.0%	
2003	\$944,443	\$134,293	\$699,420	\$6,000
	52.9%	7.5%	39.2%	0.3%
	53.1%	7.6%	39.3%	
2004	\$1,017,104	\$34,293	\$752,735	\$88,568
	53.7%	1.8%	39.8%	4.7%
	56.4%	1.9%	41.7%	
2005	\$655,544	\$ 52,293	\$449,586	\$91,715
	52.5%	4.2%	36.0%	7.3%
	56.6%	4.5%	38.8%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-207

HAWAIIAN ELECTRIC INDUSTRIES, INC. CAPITAL STRUCTURE RATIOS 2001 - 2005 (\$000)

•	COMMON	PREFERRED	LONG-TERM	SHORT-TERM
YEAR	EQUITY	SECURITIES	DEBT	DEBT
2001	\$929,665	\$234,406	\$1,145,769	\$0
	40.2%	10.1%	49.6%	0.0%
	40.2%	10.1%	49.6%	
2002	\$1,046,300	\$234,406	\$1,106,270	
	43.8%	9.8%	46.3%	0.0%
	43.8%	9.8%	46.3%	
2003	\$1,089,031	\$234,406	\$1,064,420	\$0
	45.6%	9.8%	44.6%	0.0%
	45.6%	9.8%	44.6%	
2004	\$1,210,945	\$34,405	\$1,166,735	\$76,611
	48.7%	1.4%	46.9%	3.1%
•	50.2%	1.4%	48.4%	
2005	\$1,216,630	\$34,293	\$1,142,993	\$141,758
	48.0%	1.4%	45.1%	5.6%
	50.8%	1.4%	47.7%	

Note: Percentages may not total 100.0% due to rounding.

Source: Hawaiian Electric Industries, Inc. Form 10-K.

AUS UTILITY REPORTS ELECTRIC UTILITY GROUPS AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

COMPARISON COMPANIES BASIS FOR SELECTION USING COMMISSION CRITERIA

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ Bond Rating
Hawaiian Electric Industries	\$2,300,000	83%	53%	. 2	Baa2
Comparison Group*					
CH Energy Group	\$750,000	52%	58%	1	A2
Great Plains Energy Pinnacle West Capital	\$2,500,000 \$4,800,000	44% 75%	51% 57%	2	A3 Baa1
PNM Resources	\$2,000,000	78%	42%	2	Baa2
Westar Energy	\$2,000,000	98%	47%	2	Baa3
Wisconsin Energy	\$4,900,000	62%	47%	2	A1

^{*} Selected using following criteria: Market cap of \$500 million to \$5 billion. Electric Revenues of 40% or greater. Common Equity Ratio of 40% or greater. Value Line Safety of 1, 2 or 3. Moody's bond ratings of BBB or A.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES BASIS FOR SELECTION USING PARCELL CRITERIA

Company	Net Utility Plant (000)	Percent Revenues Electric	Common Equity Ratio	Standard & Poor's Stock Ranking	Moody's/ Bond Rating
Hawaiian Electric Industries	\$2,542,800	83%	53%	B+	Baa2
Comparison Group*					
Cleco Corp Empire District Electric IDACORP Puget Energy	\$1,188,700 \$896,000 \$2,314,300 \$4,630,900	96% 93% 98% 61%	52% 49% 50% 46%	B+ B+ B+ B+	Baa1 Baa1 A3 Baa2

^{*} Selected using following criteria: Net Utility Plant of \$600 million to \$5 billion. Electric Revenues of 60% or greater. Common Equity Ratio of 40% or greater. Standard & Poor's Stock Ranking of B or B+. Moody's bond ratings of BBB or A. No nuclear generation.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES DIVIDEND YIELD

COMPANY	DP\$	Octobe HIGH	er - Decemb LOW	er, 2006 AVERAGE	YIELD
Comparison Group - PUC Crit	eria				
CH Energy Group	\$2.16	\$54.92	\$50.25	\$52.59	4.1%
Great Plains Energy	\$1.66	\$32.85	\$30.87	\$31.86	5.2%
Pinnacle West Capital	\$2.10	\$51.00	\$45.12	\$48.06	4.4%
PNM Resources	\$0.88	\$32.07	\$27.47	\$29.77	3.0%
Westar Energy	\$1.00	\$27.24	\$23.20	\$25.22	4.0%
Wisconsin Energy	\$0.92	\$48.70	\$43.25	\$45.98	2.0%
Average					3.8%
Comparison Group - Parcell C	riteria				
Cleco Corp	\$0.90	\$26.20	\$24.78	\$25.49	3.5%
Empire District Electric	\$1.28	\$25.10	\$21.61	\$23.36	5.5%
Hawaiian Electric Industries	\$1.24	\$28.18	\$26.50	\$27.34	4.5%
IDACORP	\$1.20	\$40.17	\$37.61	\$38.89	3.1%
Puget Energy	\$1.00	\$25.91	\$22.72	\$24.32	4.1%
Average					4.1%

Source: Yahoo! Finance.

COMPARISON COMPANIES RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Averag
Comparison Group - PUC Crite	oria									
CH Energy Group	3.1%	0.0%	2.0%	1.7%	2.0%	1.8%	1.5%	2.0%	3.0%	2.2%
Great Plains Energy	0.0%	2.3%	4.4%	5.1%	3.2%	3.0%	0.0%	2.0%	2.5%	1.5%
innacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	3.5%	4.0%	3.0%	3.5%
NM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Vestar Energy	0.0%	0.0%	4.9%	3.2%	4.3%	2.5%	4.5%	4.0%	3.0%	3.8%
Visconsin Energy	6.0%	8.3%	7.4%	4.9%	7.5%	6.8%	7.0%	6.5%	7.0%	6.8%
verage						3.8%		•		3.6%
Comparison Group - Parcell C	riteria								<u>. </u>	
Cleco Corp	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.5%	4.0%	3.3%
mpire District Electric	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	1.0%	3.0%	1.3%
ławaiian Electric Industries	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.5%	2.3%
DACORP	6.3%	0.0%	0.0%	2.7%	1.3%	2.1%	4.0%	4.0%	4.0%	4.0%
uget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.0%	3.0%	3.5%	2.8%
\verage			_			2.3%				2.8%

Source: Value Line Investment Survey.

COMPARISON COMPANIES PER SHARE GROWTH RATES

	5-	Year Historic	Growth Ra	tes	Est'd	<u>'03-'05</u> to '09	-'11 Growth	Rates
COMPANY	EPS	DPS	BVP\$	Average	EPS	DPS	BVPS	Average
Comparison Group - PUC Cri	teria							
CH Energy Group	-1.5%	0.0%	2.0%	0.2%	3.0%	0.5%	2.0%	1.8%
Great Plains Energy	6.0%	0.0%	1.0%	2.3%	-0.5%	0.0%	4.5%	1.3%
Pinnacle West Capital	-4 .5%	6.5%	4.0%	2.0%	7.0%	5.0%	4.0%	5.3%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	6.0%	8.5%	5.5%	6.7%
Westar Energy	-1.5%	-14.5%	-11.0%	-9.0%	5.0%	6.5%	4.0%	5.2%
Wisconsin Energy	4.5%	-11.0%	5.0%	-0.5%	6.5%	4.5%	6.5%	5.8%
Average				-0.4%				4.4%
Comparison Group - Parcell (Criteria							
Cleco Corp	1.0%	2.0%	4.0%	2.3%	7.0%	5.0%	8.5%	6.8%
Empire District Electric	-5.0%	0.0%	2.0%	-1.0%	9.5%	0.0%	2.0%	3.8%
Hawaiian Electric Industries	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
IDACORP	-11.0%	-6.0%	3.0%	-4.7%	7.5%	-2.0%	4.5%	3.3%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average				-1.6%				3.9%

Source: Value Line Investment Survey.

COMPARISON COMPANIES DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group - PUC Cri	teria				·			
CH Energy Group	4.1%	1.8%	2.2%	0.2%	1.8%		1.5%	5.6%
Great Plains Energy	5.3%	3.0%	1.5%	2.3%	1.3%	2.0%	2.0%	7.3%
Pinnacle West Capital	4.5%	3.2%	3.5%	2.0%	5.3%	5.3%	3.9%	8.3%
PNM Resources	3.0%	5.4%	3.8%	2.8%	6.7%	9.7%	5.7%	8.7%
Westar Energy	4.0%	2.5%	3.8%		5.2%	3.0%	3.6%	7.7%
Wisconsin Energy	2.1%	6.8%	6.8%		5.8%	8.0%	6.9%	8.9%
Average	3.8%	3.8%	3.6%	1.8%	4.4%	5.6%	3.9%	7.8%
Median	,· • • • • • • • • • • • • • • • • • • •							8.0%
Composite		7.6%	7.4%	5.7%	8.2%	9.4%	7.8%	<u> </u>
Comparison Group - Parcell (Criteria							
Cleco Corp	3.6%	4.7%	3.3%	2.3%	6.8%	10.5%	5.5%	9.2%
Empire District Electric	5.5%	0.0%	1.3%		3.8%	3.0%	2.0%	7.6%
Hawaiian Electric Industries	4.6%	3.0%	2.3%	1.3%	1.8%	3.0%	2.3%	6.9%
IDACORP	3.1%	2.1%	4.0%		3.3%	5.0%	3.6%	6.7%
Puget Energy	4.2%	1.8%	2.8%		3.5%	4.0%	3.0%	7.2%
Average	4.2%	2.3%	2.8%	1.8%	3.9%	5.1%	3.3%	7.5%
Median								7.2%
Composite		6.5%	7.0%	6.0%	8.1%	9.3%	7.5%	

Note: Negative average values not considered.

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE 20-YEAR U.S. TREASURY BOND YIELDS RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		\$79.07			
1978	\$12.33	\$85.35	15.00%	7.90%	7.10%
1979	\$14.86	\$94.27	16.55%	8.86%	7.69%
1980	\$14.82	\$102.48	15.06%	9.97%	5.09%
1981	\$15.36	\$109.43	14.50%	11.55%	2.95%
1982	\$12.64	\$112.46	11.39%	13.50%	-2.11%
1983	\$14.03	\$116.93	12.23%	10.38%	1.85%
1984	\$16.64	\$122.47	13.90%	11.74%	2.16%
1985	\$14.61	\$125.20	11.80%	11.25%	0.55%
1986	\$14.48	\$126.82	11.49%	8.98%	2.51%
1987	\$17.50	\$134.04	13.42%	7.92%	5.50%
1988	\$23.75	\$141.32	17.25%	8.97%	8.28%
1989	\$22.87	\$147.26	15.85%	8.81%	7.04%
1990	\$21.73	\$153.01	14.47%	8.19%	6.28%
1991	\$16.29	\$158.85	10.45%	8.22%	2.23%
1992	\$19.09	\$149.74	12.37%	7.29%	5.08%
1993	\$21.89	\$180.88	13.24%	7.17%	6.07%
1994	\$30.60	\$193.06	16.37%	6.59%	9.78%
1995	\$33.96	\$215.51	16.62%	7.60%	9.02%
1996	\$38.73	\$237.08	17.11%	6.18%	10.93%
1997	\$39.72	\$249.52	16.33%	6.64%	9.69%
1998	\$37.71	\$266.40	14.62%	5.83%	8.79%
1999	\$48.17	\$290.68	17.29%	5.57%	11.72%
2000	\$50.00	\$325.80	16.22%	6.50%	9.72%
2001	\$24.69	\$338.37	7.43%	5.53%	1.90%
2002	\$27.59	\$321.72	8.36%	5.59%	2.77%
2003	\$48.73	\$367.17	14.15%	4.80%	9.35%
2004	\$58.55	\$414.75	14.98%	5.02%	9.96%
2005	\$69.93	\$453.06	16.12%	4.69%	11.43%
	ψ00.00	ψ100.00			
Average			14.09%	7.90%	6.19%

Sources: Standard & Poor's Analysts' Handbook and ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES CAPM COST RATES

COMPANY	RISK-FREE RATE	ВЕТА	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Crit	eria			
CH Energy Group	4.83%	0.85	5.90%	9.8%
Great Plains Energy	4.83%	0.95	5.90%	10.4%
Pinnacle West Capital	4.83%	1.00	5.90%	10.7%
PNM Resources	4.83%	1.00	5.90%	10.7%
Westar Energy	4.83%	0.90	5.90%	10.1%
Wisconsin Energy	4.83%	0.80	5.90%	9.6%
Average	4.83%	0.92	5.90%	10.2%
Median				10.3%
Comparison Group - Parcell C	riteria			
Cleco Corp	4.83%	1.30	5.90%	12.5%
Empire District Electric	4.83%	0.80	5.90%	9.6%
Hawaiian Electric Industries	4.83%	0.70	5.90%	9.0%
IDACORP	4.83%	1.00	5.90%	10.7%
Puget Energy	4.83%	0.80	5.90%	9.6%
Average	4.83%	0.92	5.90%	10.3%
Median	1.1.1.1.1.1.1.1.1			9.6%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES CAPM COST RATES USING IBBOTSON RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Crit	eria			
CH Energy Group	4.83%	0.85	6.50%	10.4%
Great Plains Energy	4.83%	0.95	6.50%	11.0%
Pinnacle West Capital	4.83%	1.00	6.50%	11.3%
PNM Resources	4.83%	1.00	6.50%	11.3%
Westar Energy	4.83%	0.90	6.50%	10.7%
Wisconsin Energy	4.83%	0.80	6.50%	10.0%
Average	4.83%	0.92	6.50%	10.8%
Median				10.8%
Comparison Group - Parcell C	riteria			- '''
Cleco Corp	4.83%	1.30	6.50%	13.3%
Empire District Electric	4.83%	0.80	6.50%	10.0%
Hawaiian Electric Industries	4.83%	0.70	6.50%	9.4%
IDACORP	4.83%	1.00	6.50%	11.3%
Puget Energy	4.83%	0.80	6.50%	10.0%
Average	4.83%	0.92	6.50%	10.8%
Median				10.0%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1995	1997	1998	1999	2000	2001	2002	2003	2004	2006	1992-2001 Average	2001-2005 Average	2008	2007	2009-20
Comparison Group - PUC C	iteria																		
CH Energy Group	11.0%	11.1%	107%	10.7%	77.3 %	10.0%	10.4%	10.2%	10 5%	10 4%	7.0%	2.7%	9.7%	3 2%	10.7%	3 3 N	3.0%	35%	2.0%
Greet Plains Energy	9 8%	12 0%	11.7%	13 4%	11 6%	11.7%	13 2%	8 9%	14 2%	11 5%	15.6%	18 6%	16 9%	13.7%	11 8%	14 9%	9.0%	11.5%	11 0%
Pinnacie West Capital	10.7%	10 0%	10 2%	10 6%	11 2%	11.0%	11.5%	12 3%	12.4%	12 8%	8.8%	8 3%	8 2%	5 9%	11.5%	8 0%	9.5%	9 5%	9 0%
PNM Resources	4 6%	8.0%	11.7%	0.5%	9 9%	10 0%	11.3%	9 1%	10.2%	15 8%	6 3%	6.7%	7.0%	5.5%	10.0%	9.1%	8 5%	B 5%	8 0%
Wester Energy	11.0%	12.4%	10 7%	11,1%	10 4%	-1.6%	7.1%	6 2%	3.2%	-2.2%	5 0%	10.6%	7.7%	9 6%	6.7%	6 1%	10 0%	9 5%	9 0%
Visconsin Energy	11.4%	11 6%	10 5%	12.9%	11.5%	3 2%	10.0%	11.3%	8 4%	10 6%	12.8%	11 8%	9 0%	11 8%	10.0%	11 2%	10 6%	10 5%	10 5%
kverage	9 8%	11.1%	10 9%	11 2%	11.0%	7.7%	10 6%	9 6%	9 6%	9.8%	0 2%	10 5%	9.7%	9 9%	10.1%	9.8%	9.3%	9.7%	9.4%
Composite				_											10.1%	9.8%			
Comperison Group - Par _{cell}	Criteria						•											-	
Cleco Corp	14.0%	12 4%	12,0%	13 4%	13 8%	12.8%	12 6%	12.8%	15.0%	14 6%	13.5%	11 5%	12 8%	11.6%	13 4%	12 8%	6 0%	8 0%	10 5%
mpire District Electric	10.3%	9 4%	10 8%	9 4%	9 4%	9 9%	11 8%	8 4%	10 0%	4 3%	8 4%	8.7%	5 7%	6 2%	9 3%	6 7%	7.0%	9.0%	10 5%
iswadan Electric Industries	10.0%	10 5%	11,1%	11.0%	10 5%	10.9%	11,5%	11.1%	9 8%	12 4%	11.0%	11.1%	0.3%	9.7%	11 0%	10.8%	10 0%	10 0%	11 0%
DACORP	9.0%	11.2%	10 1%	11.6%	12 1%	12.4%	12.4%	12 3%	16.7%	14 9%	7.1%	4 2%	8 2%	7.3%	12.3%	8 3%	8 5%	8 5%	8 0%
oget Energy	12.4%	11 0%	8 4%	10 2%	10 2%	7 4%	11.5%	11 8%	13 2%	7 6%	7.0%	7.4%	8 0%	8 4%	10 4%	7 8%	7.5%	8 5%	B 5%
	11.3%	10.9%	10 7%	11,1%	11 2%	10 7%	11.9%	11 3%	12.9%	10 8%	9.7%	\$ 6%	8 8%	8 0%	11.3%	9.3%	8.2%	9.0%	0.7%
Composite															11.3%	9.3%			

Source. Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES MARKET TO BOOK RATIOS

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-20 Averag
Comparison Group - PUC C	riteria															
CH Energy Group	123%	133%	107%	112%	114%	135%	155%	133%	125%	141%	152%	147%	149%	146%	128%	147%
Freat Plains Energy	160%	173%	151%	168%	161%	198%	209%	178%	173%	185%	163%	198%	216%	189%	178%	191%
innacle West Capital	118%	125%	22%	118%	133%	152%	180%	143%	145%	154%	118%	114%	130%	130%	136%	129%
NM Resources	75%	84%	87%	95%	108%	105%	106%	85%	94%	123%	95%	93%	124%	147%	96%	116%
Nestar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	118%	105%
Misconsin Energy	178%	177%	160%	172%	159%	154%	185%	152%	119%	126%	129%	147%	155%	188%	159%	145%
vverage	132%	141%	122%	132%	139%	146%	161%	130%	122%	135%	120%	135%	151%	154%	136%	139%
Composité											·	•			138%	139%
Comparison Group - Parcell	Criteria															
Claco Corp	177%	175%	156%	162%	168%	171%	163%	172%	223%	224%	154%	134%	177%	177%	161%	173%
mpire District Electric	184%	178%	143%	142%	143%	135%	188%	177%	183%	162%	132%	133%	144%	148%	162%	144%
lawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	161%	147%	162%
DACORP	155%	172%	146%	148%	188%	177%	177%	158%	189%	185%	134%	112%	125%	122%	168%	136%
Puget Energy	149%	148%	112%	119%	130%	155%	170%	148%	143%	143%	128%	129%	137%	133%	141%	134%
verage	167%	165%	140%	144%	151%	158%	170%	157%	173%	172%	140%	132%	152%	152%	160%	150%
Composite															160%	150%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group - PUC Criteria	1.7	0.92	B++	В
Comparison Group - Parcell Criteria	2.8	0.92	B+	B+
Hawaìian Electric Industries	2.0	0.70	Α	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

HAWAII ELECTRIC LIGHT COMPANY TOTAL COST OF CAPITAL

ITEM	PERCENT		COST RATE		WEI	GHTED C	OST
Short-Term Debt	7.59%		5.00%			0.38%	_
Revenue Bonds	30.96%		5.90%			1.83%	
Taxable Debt	6.48%		6.20%			0.40%	
Hybrid Securities	2.41%		7.50%			0.18%	
Preferred Stock	1.73%		8.37%			0.14%	
Common Equity	50.83%	9.50%		10.25%	4.83%		5.21%
Total	100.00%				7.76%		8.14%
						7.95%	

HAWAII ELECTRIC LIGHT COMPANY PRE-TAX COVERAGE

ITEM	_AMOUNT (\$000)	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST
Short-Term Debt	\$28,793	6.84%	5.00%	0.34%	0.34%
Revenue Bonds	\$117,455	27.91%	5.90%	1.65%	1.65%
Purchased Power (1)	\$41,366	9.83%	10.00%	0.98%	0.98%
Taxable Debt	\$24,569	5.84%	6.20%	0.36%	0.36%
Hybrid Securities	\$9,152	2.18%	7.50%	0.16%	0.16%
Preferred Stock	\$6,563	1.56%	8.37%	0.13%	0.22%
Common Equity	\$192,862	45.84%	9.88%	4.53%	7.54%
TOTAL CAPITAL	\$420,760	100.00%		8.15%	11.26%

(1) Average 2006 Purchased Power 'debt equivalent" from HELCO-WP-1818, page 11.

Pre-tax coverage =

3.38 X

Standard & Poor's Utility Benchmark Ratios:

	A	BBB
Pre-tax coverage (X) Business Position:		
5	3.5 - 4.3x	2.4 - 3.5x
Total Debt to Total Capital (%) Business Position		
5	42 - 50%	50 - 60%

Note: Since 2004, S&P no longer uses the ratio "Pre-tax Coverage" as one of its benchmark ratios. The benchmark levels shown above reflect the 1999 levels cited by S&P.

RISK PREMIUM BY DECADE AS DERIVED BY HELCO WITNESS MORIN

Year	Risk Premium	Risk Premium By Decade
1932	-20.37%	
1933	-22.28%	
1934	-30.96%	
1935	71.96%	
1938 1937	13.43% -37.34%	
1938	13.83%	
1939	3.41%	-1.04%
1940	-25.19%	
1941	-33.29%	
1942	20,18%	
1943 1944	53,84% 3.82%	
1945	43.63%	
1946	9.75%	
1947	-14.20%	
1948	5.21%	
1949	16.09%	7.98%
1950 1951	6.86% 20.65%	
1952	16.29%	
1953	6.40%	
1954	22.40%	
1955	9.15%	
1956	8.14%	
1957 1958	1.03% 41.89%	
1959	7.74%	14.06%
1960	7.08%	
1961	33.87%	
1962	-6.76%	
1963 1964	8.37% 12.92%	
1965	2.06%	
1966	-7.99%	
1967	4.29%	
1968	9.84%	F 0404
1969 1970	-10.62% -0.96%	5.31%
1971	-10.42%	
1972	-2.33%	
1973	-13.90%	
1974	-28.22%	
1975	44.10%	
1976 1977	11.53% 12.11%	
1978	-3.13%	
1979	5.54%	1.43%
1980	12.09%	
1981	15.32%	
1982 1983	3.24% 10.46%	
1984	8.71%	
1985	-1.40%	
1986	2.80%	
1987	-5.07%	
1988 1989	7.14% 10.96%	6.43%
1990	-2.18%	0.45%
1991	9.55%	
1992	-3.49%	
1993	-4.86%	
1994	-7.34% 0.00%	
1995 1996	0.98% 3.11%	
1997	6.25%	
1998	8.36%	
1999	-10.15%	0.02%
2000	50.09%	
2001	-5.54%	

Source: Helco-1702.

		CAP	PLANT	REVENUES	ELECTRIC DEVENUES	EQUITY	٧	ALUE LINE	FIN	S&P STOCK	SAP BOND	MOODY'S BOND						
COMPANY:		(\$000)	(\$000)	(\$000)	(%)	RATIO	SAFETY	BETA	STR	RANKING	RATING	RATING	COAL	Off.	GAS	NUCLEAR	HYDRO	PURCH
Aglant Energy	WPL, IES & ISP	\$4,200,000	\$4,986,200	\$3,279,600	71%	53.1%	3	0.90	₽+	В	Α-	A2	57%	-	•	10%		33%
Allegheny Energy	MALC IES A . M.	\$6,800,000	\$6,277,400	\$3,037,900	83%	31.6%	ă.	1.95	C++	B-	888-	Baa3	76%	1%	13%		10%	
Ameren Corp.	Un El & CIPSCO	\$10,900,000	\$13,572,000		79%	53.5%	1	0.75	A+	A-	888	Bast	85%			10%		
American Electric Power Company	AEP & CASW	\$14,000,000	\$24,264,000	\$12,111,000	95%	44.9%	3	1.25	B++	8	888	Baa1						
Aguita, Inc.	UtilCorp	\$1,700,000	\$1,877,300	\$1,314,200	68%	40.9%	5	1.50	C	C	В	B2	49%	4%	4%			43%
Avista Corp.	Wash Water Pwr	\$1,300,000	\$2,126,400	\$1,259,600	49%	40.6%	3	0.95	8	3	88B-	Bea3	15%		13%		31%	38%
Stack Hills Corp.	Black Hills Power	\$1,100,000	\$1,435,400	\$1,391,600	23%	52.4%	3	1.05	8+	B	888	Bast	55%		1%			44%
CMS Energy Corp.	Consumers Energy	\$3,100,000	\$7,845,000	\$8,258,000	44%	23.4%	4	1.55	C++	C	<i>BBB</i> -	Baa3	48%			16%		35%
H Energy Group, Inc.	Cen Hud G & E	\$750,000	\$779,500	\$972,500	62%	58.0%	1	0.65	A	A -	A	A2					4%	95%
CenterPoint Energy, Inc.	Houston Electric	\$4,300,000	\$8,492,000	\$9,722,000	16%	13.1%	3	0.65	8	В	889	Baa2	Sold genera	zion assets				
Central Vermont Public Service Corp		\$225,000	\$301,200	\$311,400	100%	61.6%	3	0.70	Ð		BBB	NR				46%	34%	
Cleco Corp.	Cen La Élec	\$1,300,000	\$1,188,700	\$920,200	95%	52.0%	3	1.25	B+	8+	888	Baa1	34%	9%	8%			49%
Consolidated Edison, Inc.		\$11,100,000	\$17,112,000	\$11,690,000	64%	49.0%	1	0.70	A++	B+	A	A1						100%
Constellation Energy Group	Battimore Gas & Elec	\$10,400,000	\$10,087,000	\$17,132,000	11%	51.9%	2	1,00	A	В	8 88+		30%	1%	7%	52%	8%	
OPL Inc.	Dayton P&L	\$3,100,000	\$2,572,900	\$1,254,900	100%	37.9%	3	0.95	В	B+	888		65%					
Duquesne Light Holdings, Inc.	Duquesna Light	\$1,500,000	\$1,542,100	\$922,200	79%	37.2%	4	0.95	₿	Ð	BBB+	Baa1		mion assets	n 2000			
Dominion Resources	VA Power	\$28,000,000	\$28,940,000	\$16,041,000	31%	41.1%	2	1.00	B++	B+	BBB+	Bas1	37%	4%	5%	31%		23%
TE Energy Company	Detroit Edison	\$7,200,000	\$10,830,000		57%	44,9%	3	0.75	B+	B+	888+	A3	72%			15%		11%
uka Energy Corp.	Dulos Pwr., CG&E, PSI	\$37,000,000	\$29,200,000	\$16,745,000	47%	53,1%	2	1.20	A	B+	888	Bata 1	51%			44%		4%
dison international	So. Cal Edison	\$14,500,000	\$14,469,000	\$11,852,000	81%	40.9%	3	1.15	Ð	B	B88+	A3	32%			45%	23%	
Paso Electric Co.		\$1,100,000	\$1,291,700	\$803,900	98%	47.7%	3	0.70	B+	8	888	Bua2	9%		30%	46%		15%
moire District Electric Company		\$675,000	\$896,000	\$386,200	93%	49.0%	3	0.80	B+	В	888+	Baa1	43%	13%	13%		1%	30%
nergy East Corp.	NYSEG, RG&E, CMP	\$3,300,000	\$5,783,500		56%	43.8%	2	0.90	B++	B+	88B+	EA						near 100
nterpy Corp.		\$16,200,000	\$19,197,000		81%	45.5%	2	0.85		B+	888-	Baa2	12%	11%	10%	33%		34%
celon Corp.	PECO & Comm Ed	841,000,000	\$21,981,000	\$15,357,000	88%	43.5%	1	0.80	A+	8+	888+	Ban 1				71%		22%
PL Group, Inc.	Florida P & L	\$17,500,000	\$22,453,000	\$11,846,000	78%	51.4%	1	0.85	A+	A-	A	Aa3	4%	32%	31%	11%		13%
rstEnergy Corp.	OnEd CIE, TOLMOED, JC	\$18,000,000	\$13,998,000	\$11,989,000	80%	52.4%	2	0.80	A	8+	BBB	Ban 1	44%			26%		30%
rest Plains Energy Inc.	KCP&L	\$2,500,000	\$2,765,600	\$2,604,900	44%	50.9%	2	0.90		В	888	A3	73%	1%		20%		5%
reen Mountain Power Corp.		\$175,000	\$236,900	\$245,900	100%	58.6%	3	0.60	8++	8	888	Ban1		1%	1%	41%	44%	10%
awallan Electric Industries, Inc.	Haweitari Elec. Co.	\$2,300,000	\$2,542,800	\$2,215,600	63%	53.3%	2	0.70		8+	888	Ban2		51%				39%
ACORP	Idaho Power	\$1,700,000	\$2,314,300	\$859,500	98%	50.0%	3	1.00	B+	8	A -	A3	42%				30%	22%
DU Resources Group	Montana Dak USI	\$4,600,000	\$3,049,900	\$3,455,400	5%	62.5%	1	1.00	A+	A	A -	A2	71%	1%				26%
IGE Energy Inc.	Madison Gas & Elec	\$675,000	\$667,700	\$513,400	50%	60.7%	1	0.75	A	B+	AA-	Aa3 -	62%					37%
Source Inc.	NIPSCO	\$5,800,000	\$9,554,300	\$7,099,100	16%	48.0%	3	0.90	₽+	B	888	Sea2	87%					13%
ortheast Utilities		\$3,500,000	\$6,417,200	\$5,507,300	71%	35,1%	3	0.85	8+	8	888	Bas1		•		•	•	•
STAR	Bosion Edison	\$3,400,000	\$3,701,800	\$3,243,100	79%	38.6%	1	0.80		Α-	A+	A1		ition assets i		1999		
GE Energy Corp.	Olda Gas & Elec	\$3,200,000	\$3,587,400	\$5,948,200	34%	50.5%	2	0.75	A	A -	BBB+	Baa2	62%		26%			12%
ter Tall Corp	Otter Tail Power	\$875,000	\$697,100	\$1,040,400	29%	62.9%	2	0.65	A	A-	888+	A3	49%					50%
G&E Corp.	Pacific G & E	\$16,100,000	\$19,955,000	\$11,703,000	71%	50.0%	2	1.15	D++	В	888	Bast				34%	61%	
PL Corp	Penn P & L	\$13,000,000	\$10,915,000	\$5,219,000	68%	42.0%	2	1.00	B++	В	988+	Baa1						
nnade West Capital Corp.	Artz Pub Ser	\$4,800,000	\$7,577,100	\$2,968,000	75%	56.5%	1	1.00	A	A-	888-	Bas1	26%		7%	15%		52%
spco Holdings, Inc.	Penco & Conectiv	\$4,600,000	\$7,312,000	\$8,065,500	79%	42.3%	3	0.85	B	В	989+	San1						
rogress Energy	CP&L & FI Prog	\$11,000,000	\$14,442,000	\$10,108,000	80%	43.3%	2	0.65	B++	8+	688	A3	22%	22%	22%	34%	1%	
ublic Service Enterprise Group, Inc.	PSEAG	\$18,000,000	\$13,338,000	\$12,430,000	62%	34.6%	3	0.95	B+	₿+	A-	A3						
NM Resources	P S of New Mexico	\$2,000,000	\$2,984,100	\$2,076,800	78%	42.3%	2 `	1,00	B++	B÷	688	Bas2	71%	1%	2%	25%		
iget Energy, Inc.	Puget Sound Energy	\$2,800,000	\$4,630,900	\$2,573,200	61%	45.6%	3	0.80	₿+	8	889	Ban2	22%	2%	1%		4%	71%
CANA COID.	SCEAG	\$4,600,000	\$3,734,000	\$4,777,000	39%	45.6%	2	0.60	A	В	A -	A1	67%	4%	3%	18%	5%	3%
more Energy	San Diago G & E	\$14,000,000	\$12,101,000	\$11,737,000	43%	55.1%	2	1.10	A	В	A+	A1				23%		100%
erra Pacific Resources	Nev Pwr & SP Pwr	\$3,000,000	\$5,397,600	\$3,030,200	94%	34.8%	3	1.15	8	B-	69+	(Ba1	25%	8%	6%			59%
outhern Company	GA Pwr. Alta Pwr. M Pw	\$25,000,000	\$29,480,000		98%	44.3%	1	0.65	A	A-	A	A2	67%	6%	5%	14%	3%	5%
	Tampa Elec	\$3,200,000	\$4,566,900		58%	30.0%	ġ	1.05	В	B-	B88-	Bea2	49%	1%	34%			18%
KU Corp	Texas Utilities		\$17,192,000		22%	4.0%	3	1.10	8	B	888-	Bas2						
IntSource Energy Corp.	Turson Electric Power	\$1,300,000	\$2,171,500	81,229,500	56%	24.7%	3	0.75	C++	B	BBB-	Bee2	68%	16%	10%			
IIL Holdings	United Diam	\$875,000	\$592,100	\$1,213,100	73%	52.8%	3	0.90	B+	Đ	NR	Bea2						
	Ind Ener & SIGCORP	\$2,000,000	\$2,251,900	\$2,028,000	20%	48.8%	ž	0.85	Ā	₿+	A	A3						
	Wisconsin Pub Ser	\$2,100,000	\$2,049,400	38,982,700	14%	58.7%	2	0.80	B++	Ā-	Ä+	AE2	62%				2%	36%
Vestar Energy, Inc.	KP&L	\$2,000,000	\$3,947,700	\$1,583,300	98%	47.2%	2	0.90	B++	B	BB+	Baa3	79%		7%	14%		
	We Energies	84,900,000	\$6,362,900	\$3,815,500	62%	48.7%	2	0.80	B++	B	Ā	A1	61%		3%	20%	2%	18%
fisconsin Energy Corp.																		

CH ENERGY GROUP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		23.77	•			
1976	2.68	24.72	20.8	17.5	11.1%	79%
1977	2.90	25.72	22.5	19.1	11.5%	82%
1978	3.04	26.28	22.1	19.8	11.7%	81%
1979	3.27	27.51	20.8	18.0	12.2%	72%
1980	3.38	26.49	19.9	15.0	12.5%	65%
1981	3.72	26.51	19.0	16.0	14.0%	66%
1982	3.91	26.78	24.8	17.1	14.7%	79%
1983	3.94	27.40	26.1	21.5	14.5%	88%
1984	4.43	27.91	25.6	16.1	16.0%	75%
1985	4.67	29.49	31.3	23.0	16.3%	95%
1986	4.49	31.18	39.9	26.6	14.8%	110%
1987	2.66	20.35	31.9	16.5	10.3%	94%
1988	2.63	21.24	21.9	16.9	12.6%	93%
1989	2.28	21.76	24.1	20.4	10.6%	103%
1990	2.38	22.31	24.9	20.0	10.8%	102%
1991	2.40	22.84	29.0	22.6	10.6%	114%
1992	2.55	23.60	31.3	25.9	11.0%	123%
1993	2.68	24.65	35.8	28.4	11.1%	133%
1994	2.68	25.33	30.4	22.9	10.7%	107%
1995	2.74	25.96	31.9	25.4	10.7%	112%
1996	2.99	26.87	31.5	28.8	11.3%	114%
1997	2.97	27.61	43.9	29.8	10.9%	135%
1998	2.90	28.00	47.1	38.9	10.4%	155%
1999	2.88	28.73	45.0	30.4	10.2%	133%
2000	3.05	29.38	46.3	26.1	10.5%	125%
2001	3.11	30.33	45.9	. 38.3	10.4%	141%
2002	2.12	30.31	52.4	39.9	7.0%	152%
2003	2.78	30.80	49.7	40.2	9.1%	147%
2004	2.69	31.31	49.6	43.1	8.7%	149%
2005	2.81	31.97	50.2	42.1	8.9%	146%

GREAT PLAINS ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.65			,	
1976	1.17	10.85	10.0	8.4	10.9%	86%
1977	1.00	10.93	10.8	9.4	9.2%	93%
1978	1.18	11.00	9.9	8.0	10.8%	82%
1979	1.00	10.65	9.1	7.4	9.2%	76%
1980	1.45	10.56	7.9	6.1	13.7%	66%
1981	1.61	11.12	8.3	6.5	14.9%	68%
1982	1.39	10.98	9.4	7.3	12.6%	76%
1983	2.08	11.76	11.4	8.4	18.3%	87%
1984	2.24	12.64	10.3	7.1	18.4%	71%
1985	2.21	13.55	12.3	9.0	16.9%	81%
1986	1.40	13.90	16.1	11.1	10.2%	99%
1987	1.51	14.22	15.6	10.5	10.7%	93%
1988	1.60	13.10	16.1	12.4	11.7%	104%
1989	1.66	13.50	18.1	14.1	12.5%	121%
1990	1.66	13.75	17.9	14.6	12.2%	119%
1991	1.58	13.90	23.8	17.1	11.4%	148%
1992	1.35	13.79	24.5	19.9	9.8%	160%
1993	1.66	13.99	26.3	21.8	12.0%	173%
1994	1.64	14.13	23.9	18.6	11.7%	151%
1995	1.92	14.50	26.6	21.5	13.4%	168%
1996	1.69	14.71	29.4	23.6	11.6%	181%
1997	1.69	14.19	29.9	27.4	11.7%	198%
1998	1.89	14.41	31.8	28.0	13.2%	209%
1999	1.26	13.97	29.6	20.8	8.9%	178%
2000	2.05	14.88	29.0	20.9	14.2%	173%
2001	1.59	12.59	27.6	23.2	11.6%	185%
2002	2.04	13.58	27.0	15.7	15.6%	163%
2003	2.27	13.82	32.8	21.4	16.6%	198%
2004	2.46	15.35	35.7	27.9	16.9%	218%
2005	2.18	16.37	32.8	27.1	13.7%	189%

PINNACLE WEST

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		19.98				
1976	2.47	20.64	19.9	15.0	12.2%	86%
1977	3.02	21.83	21.4	18.1	14.2%	93%
1978	3.15	22.56	21.6	18.8	14.2%	91%
1979	2.90	22.75	21.4	16.9	12.8%	85%
1980	2.75	21.97	19.6	14.6	12.3%	76%
1981	3.26	22,13	19.6	15.1	14.8%	79%
1982	3.30	22.94	25.1	18.0	14.6%	96%
1983	3.46	23.78	26.5	17.8	14.8%	95%
1984	3.65	24.18	22.6	14.5	15.2%	77%
1985	3.88	25.36	28.1	20.6	15.7%	98%
1986	3.04	25.84	32.0	26.0	11.9%	113%
1987	3.21	26.62	32.8	26.4	12.2%	113%
1988	2.15	23.46	29.8	15.0	8.6%	89%
1989	1.44	16.31	16.4	5.0	7.2%	54%
1990	0.81	17.40	18.6	9.4	4.8%	83%
1991	-3.90	15.23	17.9	9.6	-23.9%	84%
1992	1.73	17.00	20.5	16.8	10.7%	116%
1993	1.95	18.87	25.3	19.6	10.9%	125%
1994	1.99	20.32	22.8	16	10.2%	99%
1995	2.22	21.49	· 28.9	19.6	10.6%	116%
1996	2.47	22.51	32.3	26.3	11.2%	133%
1997	2.76	23.90	42.8	27.6	11.9%	152%
1998	2.85	25.50	49.3	39.4	11.5%	180%
1999	3.18	26.00	43.4	30.2	12.3%	143%
2000	3.35	28.09	52.7	25.7	12.4%	145%
2001	3.68	29.46	50.7	37.7	12.8%	154%
2002	2.53	29.44	46.7	21.7	8.6%	116%
2003	2.52	31.0	40.5	28.3	8.3%	114%
2004	2.58	32.14	45.8	36.3	8.2%	130%
2005	2.31	34.57	46.7	39.8	6.9%	130%

PNM RESOURCES

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
	•	13.86				
1976	1.44	14.04	16.3	11.7	10.3%	100%
1977	1.64	14.40	16.0	13.3	11.5%	103%
1978	1.89	14.57	14.9	12.3	13.0%	94%
1979	1.98	14.84	14.3	11.6	13.5%	88%
1980	2.24	15.57	14.5	10.2	14.7%	81%
1981	2.22	15.93	16.6	12.9	14.1%	94%
1982	2.15	16.24	18.7	14.4	13.4%	103%
1983	1.86	16.80	19.7	15.2	11.3%	106%
1984	2.07	16.85	17.7	13.0	12.3%	91%
1985	2.20	17.15	20.5	15.9	12.9%	107%
1986	2.19	17.67	25.3	18.7	12.6%	126%
1987	1.33	17.12	26.2	11.6	7.6%	109%
1988	1.31	12.02	14.9	7.3	9.0%	76%
1989	1.15	12.01	10.6	7.2	9.6%	74%
1990	0.21	11.57	10.3	5.3	1.8%	66%
1991	0.21	11.79	7.7	5.1	1.8%	55%
1992	0.50	10.00	9.4	6.3	4.6%	72%
1993	0.81	8.86	9.3	6.5	8.6%	. 84%
1994	1.11	10.08	9.1	7.3	11.7%	87%
1995	0.91	11.22	12.2	8.1	8.5%	95%
1996	1.15	12.04	13.7	11.5	9.9%	108%
1997	1.25	12.84	15.8	10.5	10.0%	106%
1998	1.50	13.75	16.5	11.6	11.3%	106%
1999	1.29	14.74	14.3	9.9	9.1%	85%
2000	1.55	15.76	18.9	9.8	10.2%	94%
2001	2.61	17.25	25.2	15.3	15.8%	123%
2002	1.07	16.60	20.5	11.5	6.3%	95%
2003	1.15	17.84	19.6	12.6	6.7%	93%
2004	1.43	18.19	26.1	18.7	7.9%	124%
2005	1.59	18.70	30.5	23.8	8.6%	147%

Westar Energy

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.42				
1976	1.37	10.80	10.3	9.0	12.9%	91%
1977	1.51	11.41	11.8	9.9	13.6%	98%
1978	1.37	11.56	11.3	9.5	11.9%	91%
1979	1.40	11.53	10.4	7.6	12.1%	78%
1980	1.61	12.04	9.7	7.3	13.7%	72%
1981	1.65	12.00	10.0	8.1	13.7%	75%
1982	1.80	12.55	12.4	8.8	14.7%	86%
1983	2.33	13.59	15.3	12.0	17.8%	104%
1984	2.40	14.62	17.6	13.8	17.0%	111%
1985	2.47	15.51	20.7	16.2	16.4%	122%
1986	2.43	16.35	32.5	19.8	15.3%	164%
1987	2.46	16.98	30.8	20.0	14.8%	152%
1988	2.25	17.51	27.0	22.3	13.0%	143%
1989	2.05	17.80	25.4	21.6	11.6%	133%
1990	2.25	18.25	25.1	19.8	12.5%	125%
1991	2.41	18.59	28.5	20.8	13.1%	134%
1992	2.20	21.51	32.6	25.1	11.0%	144%
1993	2.76	23.08	37.3	30.4	12.4%	152%
1994	2.51	23.93	34.9	26.1	10.7%	130%
1995	2.71	24.71	34.0	28.6	11.1%	129%
1996	2.60	25.14	34.9	28.0	10.4%	126%
1997	-0.46	30.79	43.4	29.8	-1.6%	131%
1998	2.13	29.40	44.2	32.6	7.1%	128%
1999	1.48	27.83	33.9	16.8	5.2%	89%
2000	0.89	27.20	25.9	14.7	3.2%	74%
2001	-0.58	25.97	25.9	15.6	-2.2%	78%
2002	1.00	13.68	18.0	8.5	5.0%	67%
2003	1.48	14.23	20.5	9.8	10.6%	109%
2004	1.17	16.13	22.9	17.1	7.7%	132%
2005	1.55	16.31	25.0	21.1	9.6%	142%

WISCONSIN ENERGY CORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		5.70				
1976	0.71	5.99	7.1	5.4	12.1%	107%
1977	0.75	6.27	7.3	6.2	12.2%	110%
1978	0.78	6.56	6.9	5.6	12.2%	97%
1979	0.83	6.83	6.0	5.0	12.4%	82%
1980	0.78	6.96	6.0	4.3	11.3%	75%
1981	0.98	7.25	6.5	4.5	13.8%	77%
1982	1.20	7.78	8.6	5.8	16.0%	96%
1983	1.32	8.40	9.5	7.3	16.3%	104%
1984	1.45	9.06	11.2	8.4	16.6%	112%
1985	1.58	9.88	13.5	10.3	16.7%	126%
1986	1.58	10.58	21.5	12.8	15.4%	168%
1987	1,70	11.30	19.3	14.0	15.5%	152%
1988	1.94	12.18	18.6	15.0	16.5%	143%
1989	1.92	13.01	21.4	16.8	15.2%	152%
1990	1.85	13.70	21.7	17.8	13.9%	148%
1991	1.87	14.35	26.4	20.0	13.3%	165%
1992	1.67	14.97	28.5	23.8	11.4%	178%
1993	1.81	15.67	29.4	24.8	11.8%	177%
1994	1.67	16.01	27.5	23.1	10.5%	160%
1995	2.13	16.89	30.9	25.8	12.9%	172%
1996	1.97	17.42	32.0	26.0	11.5%	169%
1997	0.54	16.51	29.1	23.0	3.2%	154%
1998	1.65	16.46	34.0	27.0	10.0%	185%
1999	1.88	16.89	31.6	19.1	11.3%	152%
2000	1.08	17.00	23.6	16.8	6.4%	119%
2001	1.84	17.81	24.6	19.1	10.6%	126%
2002	2.32	18.44	26.5	20.2	12.8%	129%
2003	2.26	19.92	33.7	22.6	11.8%	147%
2004	1.85	21.31	34.6	29.5	9.0%	155%
2005	2.56	22.91	40.8	33.3	11.6%	168%

CLECO

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
1976		,				
1977	0.23	2.57				
1978	0.28	3.27				
1979	1.48	6.14				
1980	0.95	3.65				
1981	0.62	4.39	3.7	3.5		90%
1982	0.54	4.59	3.9	3.2	12.0%	79%
1983	0.72	4.82	4.9	3.7	15.3%	91%
1984	0.92	5.23	5.6	4.4	18.3%	100%
1985	0.91	5.62	7.6	5.3	16.8%	119%
1986	0.81	5.98	9.5	7.2	14.0%	144%
1987	0.88	6.23	9.3	7.2	14.4%	135%
1988	0.90	6.56	8.5	7.7	14.1%	127%
1989	0.89	6.87	9.0	3.9	13.3%	96%
1990	0.93	7.16	9.1	7.9	13.3%	121%
1991	0.96	6.76	12.3	8.6	13.8%	150%
1992	0.97	7.06	13.1	11.4	14.0%	177%
1993	0.89	7.29	13.6	11.5	12.4%	175%
1994	0.96	7.56	12.8	10.4	12.9%	156%
1995	1.04	7.91	14.1	11.0	13.4%	162%
1996	1.12	8.30	· 14.6	12.6	13.8%	168%
1997	1.09	8.68	16.6	12.4	12.8%	171%
1998	1.12	9.07	18.1	14.3	12.6%	183%
1999	1.19	9.44	17.8	14.1	12.9%	172%
2000	1.46	10.04	28.3	15.1	15.0%	223%
2001	1.51	10.69	27.3	19.2	14.6%	224%
2002	1.52	11.77	24.9	9.7	13.5%	154%
2003	1.26	10.09	18.4	11.0	11.5%	134%
2004	1.32	10.83	20.8	16.2	12.6%	177%
2005	1.42	13.69	24.4	18.9	11.6%	177%

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EMPIRE DISTRICT

Year	EPS	BVPS	Hí Pr	Lo Pr	ROE	M/B
		6.93				
1976	0.79	7.03	8.2	6.8	11.3%	107%
1977	0.92	7.28	8.7	7.5	12.9%	113%
1978	0.85	7.39	7.9	6.6	11.6%	99%
1979	0.86	7.49	7.3	5.6	11.6%	87%.
1980	0.79	7.50	6.5	5.0	10.5%	77%
1981	0.67	7.35	5.8	4.9	9.0%	72%
1982	1.06	7.59	7.2	5.1	14.2%	82%
1983	1.26	8.01	8.7	6.8	16.2%	99%
1984	1.48	8.63	9.9	7:4	17.8%	104%
1985	1.38	9.14	12.3	9.3	15.5%	122%
1986	1.43	9.67	18.0	11.6	15.2%	157%
1987	1.48	10.22	17.0	13.7	14.9%	154%
1988	1.53	10.75	15.9	13.8	14.6%	142%
1989	1.47	11.17	16.1	13.3	13.4%	134%
1990	1.28	11.75	15.8	13.6	11.2%	128%
1991	1.43	12.08	24.1	14.8	12.0%	163%
1992	1.26	12.29	24.8	20.1	10.3%	184%
1993	1.16	12.37	24.8	19.1	9.4%	178%
1994	1.32	12.47	20.5	15.0	10.6%	143%
1995	1.18	12.69	19.8	16.0	9.4%	142%
1996	1.21	12.96	19.5	17.1	9.4%	143%
1997	1.29	13.06	20.0	15.8	9.9%	138%
1998	1.53 .	13.43	26.1	18.4	11.6%	168%
1999	1.13	13.48	26.8	20.7	8.4%	177%
2000	1.35	13.65	30.8	18.9	10.0%	183%
2001	0.59	13.58	26.6	17.5	4.3%	162%
2002	1.19	14.59	22.0	15.1	8.4%	132%
2003	1.29	15.17	22.5	17.0	8.7%	133%
2004	0.86	14.76	23.5	19.5	5.7%	144%
2005	0.92	15.08	25.0	19.3	6.2%	148%

HAWAIIAN ELECTRIC

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		. 6.18				
1976	0.74	6.47	6.1	5.0	11.6%	87%
1977	0.79	6.73	6.7	5.8	12.0%	95%
1978	0.85	7.05	7.1	6.0	12.3%	95%
1979	0.92	7.39	6.9	5.9	12.7%	89%
1980	0.95	7.51	6.2	4.6	12.7%	72%
1981	0.98	7.66	6.7	5.2	12.9%	78%
1982	0.59	7.92	7.7	5.9	7.6%	87%
1983	1.03	8.16	8.5	6.8	12.8%	95%
1984	1.13	8.50	10.7	7.8	13.5%	111%
1985	1.20	8.92	12.7	9.8	13.8%	129%
1986	1.29	9.48	17.8	12.3	14.0%	163%
1987	1.43	9.80	17.2	. 11.2	14.8%	147%
1988	1.45	10.98	16.8	13.0	14.0%	143%
1989	1.53	11.59	20.2	14.7	13.6%	154%
1990	1.01	11.65	20.0	13.7	8.7%	145%
1991	1.20	12.18	19.0	14.7	10.1%	141%
1992	1.27	11.06	22.3	17.4	10.9%	171%
1993	1.19	11.62	19.4	15.5	10.5%	154%
1994	1.30	11.90	18.3	14.9	11.1%	141%
1995	1.33	12.25	19.9	16.1	11.0%	149%
1996	1.30	12.52	19.8	16.6	10.5%	147%
1997	1.38	12.77	20.8	16.4	10.9%	147%
1998	1.48	12.87	21.3	18.2	11.5%	154%
1999	1.45	13.16	20.3	14.0	11.1%	132%
2000	1.27	12.72	19.0	13.8	9.8%	127%
2001	1.60	13.06	20.6	16.8	12.4%	145%
2002	1.62	14.21	24.5	17.3	11.9%	153%
2003	1.58	14.36	24.0	19.1	11.1%	151%
2004	1.36	15.01	29.5	23.0	9.3%	179%
2005	1.46	15.02	29.8	24.6	9.7%	181%

IDACORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		13.71				
1976	1.54	14.19	14.5	11.8	11.0%	94%
1977	1,10	14.20	15.1	13.0	7.7%	99%
1978	1.48	14.44	15.6	13.0	10.3%	100%
1979	1.21	14.26	13.8	12.0	8.4%	90%
1980	1.52	14.07	13.2	10.1	10.7%	82%
1981	1.53	14.26	11.9	9.1	10.8%	74%
1982	2.36	15.01	14.6	10.3	16.1%	85%
1983	2.25	15.77	17.4	14.3	14.6%	103%
1984	2.81	16.74	19.3	15.4	17.3%	107%
1985	2,16	17.29	24.5	18.8	12.7%	127%
1986	2.00	17.46	30.9	22,8	11.5%	155%
1987	1.30	17.29	30.3	19.0	7.5%	142%
1988	1.32	16.81	25.4	19.5	7.7%	132%
1989	2.37	17.35	30.0	22.0	13.9%	152%
1990	1.91	17.40	29.4	22.8	11.0%	150%
1991	.1.56	17.06	28.8	24.3	9.1%	154%
1992	1,55	17.28	28.8	24.4	9.0%	155%
1993	1.97	17.86	33.0	27.3	11.2%	172%
1994	1.80	17.91	30.6	21.8	10.1%	146%
1995	2.10	18.15	30.0	23.4	11.6%	148%
1996	2.21	18.47	34.3	27.3	12.1%	168%
1997	2.32	18.93	37.8	28.5	12.4%	177%
1998	2.37	19.42	38.1	29.9	12.4%	177%
1999	2.43	20.02	36.5	26.0	12.3%	158%
2000	3.50	21.82	53.0	25.9	16.7%	189%
2001	3,35	23.15	49.4	33.6	14.9%	185%
2002	1.63	23.01	41.0	20.9	7.1%	134%
2003	0.96	22.54	30.2	20.6	4.2%	112%
2004	1.90	23.88	32.9	25.3	8.2%	125%
2005	1.75	24.04	32.1	26.2	7.3%	122%

PUGET ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		16.99				
1976	1.92	17.99	16.8	12.7	11.0%	84%
1977	1.88	18.36	18.4	15.5	10.3%	93%
1978	2.17	18.63	18.3	15.6	11.7%	92%
1979	1.67	17.93	17.5	13.6	9.1%	85%
1980	1.60	17.15	15.1	11.0	9.1%	74%
1981	2.86	17.44	14.3	11.5	16.5%	75%
1982	2.29	17.42	16.9	12.4	13.1%	84%
1983	1.93	17.04	16.5	13.1	11.2%	86%
1984	1.52	15.42	15.0	9.3	9.4%	75%
1985	2.07	15.70	18.4	12.6	13.3%	100%
1986	1.74	15.29	25.3	17.6	11.2%	138%
1987	2.13	15.50	22.5	17.8	13.8%	131%
1988	2.14	15.98	20.3	18.0	13.6%	122%
1989	2.13	16.12	22.5	18.0	13.3%	126%
1990	2.16	16.52	22.5	18.6	13.2%	126%
1991	2.21	16.96	26.9	19.1	13.2%	137%
1992	2.16	17.76	27.9	23.9	12.4%	149%
1993	2.00	18.65	29.8	23.5	11.0%	146%
1994	1.64	18.43	24.9	16.5	8.8%	112%
1995	1.89	18.48	24.0	20.1	10.2%	119%
1996	1.89	18.53	26.0	22.1	10.2%	130%
1997	1.28	16.06	30.2	23.5	7.4%	155%
1998	1.85	16.00	30.3	24.1	11.5%	170%
1999	1.91	16.24	28.4	18.6	11.8%	146%
2000	2.16	16.61	28.0	19.1	13.2%	143%
2001	1.22	15.66	27.8	18.5	7.6%	143%
2002	1.24	16.27	23.6	16.6	7.8%	126%
2003	1.22	16.71	24.4	18.1	7.4%	129%
2004	1.32	16.24	24.8	20.5	8.0%	137%
2005	1.42	17.52	24.6	20.2	8.4%	133%

		Book	Value Per	Share			Stock Price		
Year	EPS	Y-B	Y-E	Average	ROE	High	Low	Average	M/B
1977			\$79.07						
1978	\$12,33	\$79.07	\$85.35	\$82.21	15.00%	\$106.99	\$86.90	\$96.95	117.92%
1979	\$14.86	\$85.35	\$94.27	\$89.81	16.55%	\$111.27	\$96.13	\$103.70	115.47%
1980	\$14.82	\$94.27	\$102.48	\$98.38	15.06%	\$140.52	\$98.22	\$119.37	121.34%
1981	\$15.36	\$102.48	\$109.43	\$105.96	14.50%	\$138.12	\$112.77	\$125.45	118.39%
1982	\$12.64	\$109.43	\$112.46	\$110.95	11.39%	\$143.02	\$102.42	\$122.72	110.61%
1983	\$14.03	\$112,46	\$116.93	\$114.70	12.23%	\$172.65	\$138.34	\$155.50	135.57%
1984	\$16.64	\$116.93	\$122.47	\$119.70	13.90%	\$170.41	\$147.82	\$159.12	132.93%
1985	\$14.61	\$122.47	\$125.20	\$123.84	11.80%	\$212.02	\$163.68	\$187.85	151.69%
1986	\$14.48	\$125.20	\$126.82	\$126.01	11.49%	\$254.00	\$203.49	\$228.75	181.53%
1987	\$17.50	\$126.82	\$134.07	\$130.45	13.42%	\$336.77	\$223.92	\$280.35	214.91%
1988	\$23.75	\$134.07	\$141.32	\$137.70	17.25%	\$283.66	\$242.63	\$263.15	191.11%
1989	\$22.87	\$141.32	\$147.26	\$144.29	15.85%	\$359.80	\$275.31	\$317.56	220.08%
1990	\$21.73	\$147.26	\$153.01	\$150.14	14.47%	\$368.95	\$295.46	\$332.21	221.27%
1991	\$16.29	\$153.01	\$158.85	\$155.93	10.45%	\$417.09	\$311.49	\$364.29	233.62%
1992	\$18.86	\$158.85	\$149.74	\$154.30	12.22%	\$441.28	\$394.50	\$417.89	270.84%
1993	\$21.89	\$149.74	\$180.88	\$165.31	13.24%	\$470.94	\$429.05	\$450.00	272.21%
1994	\$30.60	\$180.88	\$193.06	\$186.97	16.37%	\$482.00	\$438.92	\$460.46	246.27%
1995	\$33.96	\$193.06	\$218.51	\$204.79	16.58%	\$621.69	\$459.11	\$540.40	263.89%
1996	\$38.73	\$216.51	\$237.08	\$226.80	17.08%	\$757.03	\$598.48	\$677.76	298.84%
1997	\$39.72	\$237.08	\$249.52	\$243.30	16.33%	\$983.79	\$737.01	\$860.40	353.64%
1998	\$37.71	\$249.52	\$266.40	\$257.96	14.62%	\$1,241.81	\$927.69	\$1,084.75	420.51%
1999	\$48.17	\$266.40	\$290.68	\$278.54	17.29%	\$1,469.25	\$1,212.18	\$1,340.72	481.34%
2000	\$50.00	\$290.68	\$325.80	\$308.24	16.22%	\$1,527.46	\$1,264.74	\$1,398.10	452.93%
2001	\$24.70	\$325.80	\$337.37	\$331.59	7.45%	\$1,373.73	\$965.80	\$1,169.77	352.78%
2002	\$27.59	\$337.37	\$321.72	\$329.55	8.37%	\$1,172.51	\$776.76	\$974.64	295.75%
2003	\$48.73	\$321.72	\$367.17	\$344.45	14.15%	\$1,111.92	\$800.73	\$956.33	277.64%
2004	\$58.55	\$367.17	\$414.75	\$390.96	14.98%	\$1,213.55	\$1,063.23	\$1,138.39	291.18%
2005	\$69.93	\$414.75	\$453.08	\$433.91	16.12%	\$1,272.74	\$1,137.50	\$1,205.12	277.74%

Company	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Comparison Group - PUC Cr	iteria					
CH Energy Group	1	0.85	Α	4.00	A -	3.67
Great Plains Energy	2	0.95	Α	4.00	В	3.00
Pinnacle West Capital	<u>-</u>	1.00	Α	4.00	A-	3.67
PNM Resources	2	1.00	B++	3.67	B+	3.33
Westar Energy	2	0.90	B++	3.67	В .	3.00
Wisconsin Energy	2 2	0.80	B++	3.67	В	3.00
Average	1.7	0.92	B++	3.84	В	3.28
Comparison Group - Parcell	Criteria	 				
Cleco Corp	3	1.30	B++	3.33	B+	3.33
Empire District Electric	3	0.80	B+	3.33	В	3.00
Hawaiial Electric Industries	2	0.70	Α	. 4.00	B+	3.33
IDAÇORP	3	1.00	B+	3.33	В	3.00
Puget Energy	3 ,	0.80	8+	3.33	В	3.00
Average	2.8	0.92	B+	3.46	B+	3.13

NDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Automobile & Components			<u>. </u>			
Harley-Davidson	3	1.1	B++	3.67	A+	4.33
Johnson Controls	2	1	Α	4	A+	4.33
Ford Motor	3	1.25	В	3	В	3
General Motors	3	1.25	B++	3.67	В	3
Goodyear Tire & Rubber	4	1.5	C+	2.33	B-	2.67
Dana	3	1.6	B+	3.33	B-	2.67
Delphi	3	1.15	В	3	В	3
Cooper Tire & Rubber	3	1	B++	3.67	B+	3.33
Visteon	4	1.35	?		NR	*
Consumer Durables & Apparel	•	1.50	•			
Pulte Homes	3	1.2	Α	4	Α	4
Coach	3	1.25	Ä	4	NR	•
Nike	3	0.9	A+	4.33	A	4
KB Home	3	1.2	Ä	4	Ä	4
Centex	3	1.3	B++	3.67	A+	4.33
Black & Decker	3	1.05	_ B+	3.33	B+	3.33
Fortune Brands	. 2	0.8	Ā	4	В	3
Brunswick	3	1.2	B++	3.67	B	3
VF	3	0.95	B++	3.67	Ā-	3.67
Liz Claibome	1	0.95	_ A+	4.33	Ä	4
Stanley.Works	3	1	B++	3.67	B+	3.33
Reebok International	3	1.05	A	4	В	3
Mattel	3	0.75	B++	3.67	B+	3.33
Whirlpool	3	1.25	B++	3.67	В.	3
Legget and Platt	2	1.05	A	4	Β+	3.33
Hasbro	3	0.95	B+	3.33	В,	3
Eastman Kodak	3	1.1	B+	3.33	B-	2.67
Snap-on	2	1.1	C++	2.67	В	3
Jones Apparel Group	3	1.1	B++	3.67	B+	3.33
Newell Rubbermaid	3	0.85	B+	3.33	٠.	3.00
Maytag	4	1.4	C++	2.67	В	3
lotels, Restaurants & Leisure	7	1.7	0	2.01	D	5
Carnival	3	1.25	B+	3.33	A+	4.33
Starbucks	3	0.8	A	4	B+	3.33
McDonald's	1	1	A++	4.67	A	3.33
Marriot Intl.	3	1	ATT	4.07	B+	3.33
YUM! Brands	3	0.6	B+	3.33	NR	3.33
	3		В			
Starwood Hotels & Resorts		1.25		3	NR	0.00
Intl. Game Technology	3	0.95	B+	3.33	B+	3.33
Harrah's Entertainment	3	0.95	В	3	В	3
Hilton Hotels	3	1.15	В	3	В	3
Darden Restaurants	3	0.85	A	4	A-	3.67
Wendy's Intl.	2	0.75	Α	4	A-	3.67
Media	_	4 ^-			_	_
Walt Disney	3	1.35	Α	4	· B	3
McGraw-Hill	1	0.75	A +	4.33	54	

Univision Communications Gannett 1 0.9 A++ 4.67 A 4 Comcast 3 1.35 B+ 3.33 NR Heredith 3 0.85 B+ 3.33 A- Tirne Warmer 3 1.55 B+ 3.67 NR Tibune 1 0.9 A+ 4.33 B+ 3.3 Clear Channel Communications 3 1.55 B B+ 3.67 NR Knight-Ridder 1 0.9 A+ 4.33 A- 3.6 Clear Channel Communications 3 1.5 B 3 B- 2.6 New York Times 2 0.9 A 4 A- 3.6 Viacom 3 1.45 B+ 3.33 B- 2.6 Dow Jones 2 1.05 B++ 3.67 B 3 C 2- Dow Jones 2 1.05 B++ 3.67 B 3 C 2- Dow Jones 3 1.35 B 3 C 2- Dow Jones 1 1.35 B 3 C 2- Dow Jones 2 1.05 B++ 3.67 B 3- NR Retailing eBay 3 1.35 B 3 C 2- Staples 3 1.35 B 3 NR Retailing eBay 3 1.5 A+ 4.33 NR Staples 3 1.1 B+ 3.33 B+ 3.3 Best Buy 3 1.2 B+ 3.33 B+ 3.3 Best Buy 3 1.3 A 4 B 3. Home Depot 2 1.25 A++ 4.67 A- 3.4 Bed Bath & Beyond 2 1.2 A++ 4.67 A- 3.4 Bed Bath & Beyond 3 1.2 A++ 4.67 A- 3.4 Bed Bath & Beyond 3 1.1 B++ 3.67 B- 2. OfficeMax Dollar General 3 1.15 A 4 A A Target 3 1.15 A 4 B+ 3.3 Limited Brands 3 1.15 A 4 B+ 3.3 Limited Brands 3 1.15 A 4 B+ 3.3 Circuit City Stores 3 1.16 A 4 B+ 3. Circuit City Stores 3 1.16 A 4 A+ 4. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. Circuit City Stores 3 1.2 B+ 3.33 B+ 3. City Stores 3 1.3 B+ 3.33 B+ 3. City Stores 4 A A A A A A A A A A A	INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Univision Communications Gannett Ganne	Omnicom Group	3	1.25	B++	3.67	A+	4.33
Gannett				B+	3.33	NR	
Comcast 3 1.35 B- 2.6				A++			4
Meredith 3 0.85 B+ 3.33 A- 3.67 NR Tirnbune 1 0.9 A+ 4.33 B+ 3.3 Knight-Ridder 1 0.85 A+ 4.33 A- 3.6 Clear Channel Communications 3 1.5 B 3 B- 2.6 New York Times 2 0.9 A 4 A- 3.6 Viacom 3 1.45 B+ 3.33 B- 2.6 Dow Jones 2 1.05 B++ 3.67 B 3 Interpublic Group 3 1.35 B+ 3.67 B 3 News Corp 3 1.35 B+ 3.33 NR Retailing BB 3 1.5 A+ 4.33 NR Staples 3 1.5 A+ 4.33 NR Staples 3 1.5 A+ 4.33 NR Staples			1.35			B-	2,67
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Tribune 1 0.9 A+ 4.33 B+ 3.5 Knight-Ridder 1 0.85 A+ 4.33 A- 3.6 Clear Channel Communications 3 1.5 B 3 B- 2.6 New York Times 2 0.9 A 4 A- 3.6 Viacom 3 1.45 B+ 3.33 B- 2.6 Dow Jones 2 1.05 B++ 3.67 B 3.6 Interpublic Group 3 1.35 B 3 C 2 News Corp 3 1.35 B 3 C 2 News Corp 3 1.35 B 3 C 2 News Corp 3 1.35 B 3 C 2 Staples 3 1.35 A+ 4.33 NR Staples 3 1.35 A 4 B+ 3.3 Lowe's 3 1.1 A+ 4.33 NR Staples 3 1.3 B+ 3.33 B+ 3.3 Best Buy 3 1.2 B+ 3.33 B+ 3.3 Best Buy 3 1.3 A 4 B 3.3 Best Buy 3 1.3 A 4 B 3.3 Best Buy 3 1.3 B+ 3.33 B+ 3.3 Best Buy 3 1.3 B+ 3.67 B- 2.0 Sherwin-Williams 2 1.05 A 4 A A A A A A A A A A A A A A A A A				B++			
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New York Times							2.67
Viacom 3 1.45 B+ 3.33 B- 2.10 Dow Jones 2 1.05 B++ 3.67 B 3 Interpublic Group 3 1.35 B 3 C 2 News Corp 3 1.3 B+ 3.33 NR Retailing eBay 3 1.5 A+ 4.33 NR Staples 3 1.35 A 4 B+ 3.3 Lowe's 3 1.1 A+ 4.33 A+ 4. Nordstrom 3 1.2 B+ 3.33 B+ 3. Best Buy 3 1.3 A 4 B+ 3.3 B+ 4. 4. 4. 4. 4. 4. 4. 4. 4. 4. 4. 4. 4. 4. <t< td=""><td></td><td></td><td></td><td></td><td></td><td></td><td>3.67</td></t<>							3.67
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Bear Staples							2
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Lowe's 3	•						2 22
Nordstrom							
Best Buy							
Home Depot 2 1.25							3.33
Bed Bath & Beyond 2 1.2 A++ 4.67 A- 3.1 Gap 3 1.25 A 4 A 4 J.C. Penny 3 1.1 B++ 3.67 B- 2.1 Sherwin-Williams 2 1.05 A 4 A 4 OfficeMax B- 2.1 B- 2.1 Dollar General 3 1.15 B+ 3.33 A+ 4 TJX 3 1.05 A+ 4.33 A+ 4 Target 3 1.15 A 4 A+ 4 Kohl's 3 1.05 A 4 B+ 3 Limited Brands 3 1.15 A 4 B+ 3 Genuine Parts 1 0.9 A++ 4.67 A B+ 3 Genuine Parts 1 0.9 A++ 4.67 A B+ 3 Auto Zone 3 0.8 B 3 B+ 3 Tiffany <td< td=""><td>· · · · · · · · · · · · · · · · · · ·</td><td></td><td></td><td></td><td></td><td></td><td>3</td></td<>	· · · · · · · · · · · · · · · · · · ·						3
Gap 3 1.25 A 4 A 4 J.C. Penny 3 1.1 B++ 3.67 B- 2.0 Sherwin-Williams 2 1.05 A 4 A A OfficeMax B- 2.0 B- 2.0 Dollar General 3 1.15 B+ 3.33 A+ 4 TJX 3 1.05 A+ 4.33 A+ 4 Target 3 1.15 A 4 A+ 4 Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A+ 4 Family Dollar Stores 3 1.35 B 3<		2					4.33
J.C. Penny 3 1.1 B++ 3.67 B- 2.1 Sherwin-Williams 2 1.05 A 4 A A OfficeMax B- 2. B- 2. Dollar General 3 1.15 B+ 3.33 A+ 4. TJX 3 1.05 A+ 4.33 A+ 4. Target 3 1.15 A 4 A+ 4. Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A B+ 3. Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A+ 4 Family Dollar Stores 3	•	2					3.67
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OfficeMax B- 2. Dollar General 3 1.15 B+ 3.33 A+ 4. TJX 3 1.05 A+ 4.33 A+ 4. Target 3 1.15 A 4 A+ 4. Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Limited Brands 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A 4 B+ 3. Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 1.6 A 4 A 4 Family Dollar Stores 3 <t< td=""><td></td><td></td><td></td><td></td><td></td><td></td><td>2.67</td></t<>							2.67
Dollar General 3 1.15 B+ 3.33 A+ 4. TJX 3 1.05 A+ 4.33 A+ 4. Target 3 1.15 A 4 A+ 4. Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Limited Brands 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Family Dollar Stores 3 1.35 B <t< td=""><td></td><td>2</td><td>1.05</td><td>Α</td><td>4</td><td></td><td>4</td></t<>		2	1.05	Α	4		4
TJX 3 1.05 A+ 4.33 A+ 4. Target 3 1.15 A 4 A+ 4. Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A+ 4 Family Dollar Stores 3 1.05 A 4 A+ 4 Circuit City Stores 3 1.35 B 3 B- 2 AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 <t< td=""><td></td><td></td><td></td><td></td><td></td><td></td><td>2.67</td></t<>							2.67
Target 3 1.15 A 4 A+ 4. Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A A Family Dollar Stores 3 1.05 A 4 A+ 4 Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us <							4.33
Kohl's 3 1.05 A 4 B+ 3. Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A A Family Dollar Stores 3 1.05 A 4 A+ 4 Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Sears, Roebuck 3	TJX						4.33
Limited Brands 3 1.15 A 4 B+ 3. Genuine Parts 1 0.9 A++ 4.67 A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A A Family Dollar Stores 3 1.05 A 4 A+ 4 Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.67 NR Sears, Roebuck 3 1.	Target	3		Α	4	A+	4.33
Genuine Parts 1 0.9 A++ 4.67 A Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A A Family Dollar Stores 3 1.05 A 4 A+ 4. Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.67 NR Sears, Roebuck 3 1.1 B++ 3.67 B- 2.	Kohi's	3	1.05	Α	4	B+	3.33
Office Depot 3 1.25 A 4 B+ 3. Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A Family Dollar Stores 3 1.05 A 4 A+ 4. Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Limited Brands	3	1.15	Α	4	B+	3.33
Auto Zone 3 0.8 B 3 B+ 3. Tiffany 3 1.6 A 4 A Family Dollar Stores 3 1.05 A 4 A+ 4. Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Genuine Parts	1	0.9	A++	4.67	Α	4
Tiffany 3 1.6 A 4 A Family Dollar Stores 3 1.05 A 4 A+ 4. Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Office Depot	3	1.25		4	B+	3,33
Family Dollar Stores 3 1.05 A 4 A+ 4. Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Auto Zone		0.8	8	3	B+	3.33
Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Tiffany	3	1.6	Α	4	Α	4
Circuit City Stores 3 1.35 B 3 B- 2. AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Family Dollar Stores	3	1.05	Α	4	A+ ,	4.33
AutoNation 3 1.05 B++ 3.67 B Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.	Circuit City Stores	3	1.35	8	3	В-	2,67
Federated Department Stores 3 1.25 B+ 3.33 B RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.		3	1.05	B++	3.67	В	3
RadioShack 3 1.2 A 4 B+ 3. Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.			1.25	B+	3.33	В	3
Dillard's 3 1.2 B 3 B+ 3. May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.							3.33
May Department Stores 3 1.15 B+ 3.33 B+ 3. Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.							3.33
Toys 'R' Us 3 1.3 B+ 3.33 B- 2. Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.							3.33
Sears, Roebuck 3 1.3 B++ 3.67 NR Big Lots 3 1.1 B++ 3.67 B- 2.							2.67
Big Lots 3 1.1 B++ 3.67 B- 2.							2.07
							2.67
LOOM OF Status Versilling		3	1,1		3,01	D-	2.01
		3	0.85	A+	4.33	В	3

				,			
NDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank		
Walgreen	1	0.8	A++	4.67	A+	4.33	
Costco Wholesale	· 3	1	Α	4	B+	3.33	
Sysco	1	0.8	A++	4.67	A+	4.33	
Wal-Mart Stores	1	0.85	A++	4.67	A+	4.33	
Supervalu	3	0.85	B++	3.67	Α-	3.67	
Albertson's	3	0.8	Α	4	A-	3.67	
Safeway	3	0.95	B++	3.67	. B	3	
Kroger	3	1.1	B+	3.33	В	3	
ood, Beverage & Tobacco							
Archer Daniels Midland	3	0.7	B+	3.33	B+	3.33	
PepsiCo	1	0.65	A++	4.67	A+	4.33	
Wm. Wrigley Jr.	1	0.6	A++	4.67	A+	4.33	
Altria Group	3	0.75	8+	3.33	A+	4.33	
Hershey Foods	1	0.6	A++	4.67	A-	3.67	
Kellogg	2	0.55	B++	4.67	B+	3.33	
General Mills	1	0.55	Α	4	В	3	
Coca-Cola	1	0.6	A++	4.67	B+	3.33	
Reynold's American	3	0.9	В	3	NR		
UST	3	0.9	B+	3.33	A-	3.67	
Sara Lee	1	0.6	Α	4	Α-	3.67	
McCormick	2	0.5	B++	3.67	A+	4.3	
Brown-Forman	1	0.65	A+	4.33	Α	4	
Anheuser-Busch	1	0.6	A++	4.67	A+	4.33	
H.J. Heinz	1	0.55	A+	4.33	B+	3.33	
Pepsi Bottling Group	3	0.6	В	3	NR		
Cambell Soup	2	0.6	B++	3.67	B+	3.33	
Molson Coors Brewing	3	0.5	B+	3.33	Α	4	
ConAgra Foods	2	0.7	Α	4	Α,	4	
Coca-Cola Enterprises	1	0.6	A++	4.67	В	3	
lousehold & Personal Products							
Proctor & Gamble	1	0.55	A++	4.67	Α	4	
Gillette	1	0.65	B+	3.33	A-	3.67	
Avon Products	3	0.6	B+	3.33	Α	4	
Alberto-Culver	1	0.7	B++	3.67	B+	3.33	
Kimberly-Clark	1	0.65	A++	4.67	Α	4	
Colgate-Palmolive	1	0.65	A++	4.67	A+	4.3	
Clorox	2	0.65	B++	3.67	Α	4	
Energy							
Conoco-Phillips	2	0.85	Α	4	В	3	
CheveronTexaco	1	0.8	A++	4.67	B+	3.3	
Valero Energy	3	1.1	B++	3.67	B+	3.3	
Occidental Petroleum	1	0.85	A+	4.33	B+	3.3	
Exxon Mobil	1	0.8	A++	4.67	Ā-	3.6	
Apache	. 3	0.85	B++	3.67	B+	3.3	
Devon Energy	3	0.9	B++	3.67	B+	3.3	
	J	J. U	J	U.U.	<u> </u>	- · · ·	

NDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Burlington Resources	3	0.8	8++	3.67	В	3
EOG Resources	3	0.9	B++	3.67	В	3
XTO Energy	3	0.8	B+	3.33	B+	3.33
Unocal	2	0.9	Α	4	B+	3.33
Anadarko Petroleum	3	0.9	B+	3.33	B+	3.33
Marathon Oil	2	0.85	B++	3.67	·B+	3.33
Amerada Hess	3	0.9	B++	3.67	В	3
Halliburton	3	1.2	В	3	В	3
BJ Services	3	1.15	В	3	В	3
Baker Hughes	3	0.95	B++	3.67	В	3
Sclumberger	3	1.05	B++	3.67	B-	2.67
Ashland	2	0.8	B+	3.33	В	3
Kerr-McGee	3	1	B+	3.33	В	3
Kinder Morgan	2	0.7	B+	3.33	В	3
Nabors Industries	3	1.1	B++	3.67	В	3
Transocean	3	1.05	B+	3.33	B-	2.67
Williams	5	2.45	C++	2.67	В	3
Noble	3	0.9	В	3	B	3
Rowan	3	1.1	В	3	8-	2.67
El Paso	5	1.9	C+	2.33	NR	
anks	·	1.0	•	2.00		
Bank Of America	2	1.2	A+	4.33	Α-	3.67
Wachovia	3	1.1	B++	3.67	A-	3.67
Countrywide Financial	3	1	B++	3.67	A	4
Wells Fargo	1	0.95	Ā+	4.33	A	4
U.S. Bancorp	3	1.2	B++	3.67	B+	3.33
National City	ž	1.05	Ā	4	Ā	4
Golden West Financial	2	0.85	B++	3.67	A+	4.33
Regions Financial	2	1.05	Ā	4	A-	3.67
North Fork Bancorporation	2	0.95	B++	3.67	À	4
BB&T	1	0.95	Ā	4	A-	3.67
M&T Bank	1	0.95	Ä	4	A+	4.3
Marshall & Ilsley	1	1	Ä	4	A	4.00
Sovereign Bancorp	3	1.1	В	3	B+	3.33
PNC Financial Services Group	2	1.1	B++	3.67	NR	0.00
Synovus Financial	2	1.1	B++	3.67	A+	4.33
Sun Trust Banks	2	1.05	B++	3.67	A+	4.33
KeyCorp	3	1.05	B+	3.33	A-	3.67
Compass Bancshares	3	1.05	D,	0.00	A+	4.3
Zions Bancorporation	3	1.05	B++	3.67	A	4.5
Washington Mutual	2	0.95	A	3.07 4	Ä	4
MGIC Investment	3	1.2	B++	3.67	Ä	4
First Horizon National	3 2	0.9	B++	3.67 3.67	A+	4.3
Comerica	2	1.05	A	3.6 <i>1</i> 4		4.5.
	2				A	
AmSouth Bancorporation		0.95	A	4	A-	3.67
Huntington Bancshares	3	0.95	В	3	8+	3.3
Fifth Third Bancorp	1	1	A+	4.33	A+	4,3

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Freddie Mac	3	0.95	Α	4	A+	4.33
Fannie Mae	3	0.85	B+	3.33	NR	
Diversified Financials						
Franklin Resources	3	1.25	B++	3.67	A-	3.67
T. Rowe Price Group					Α	4
Moody's	2	0.8	B+	3.33	B+	3.33
Capital One Financial	3	1.65	Α	4	A+	4.44
Goldman Sachs Group	2	1.35	A+	4,33	NR	
American Express	2	1.5	A+	4.33	A-	3.67
Lehman Brothers Holdings	3	1.45	B+	3.33	Α	4
SLM	1	0.75	A+	4.33	A-	3.67
Merril Lynch	3	1.55	A+	4.33	A-	3.67
Bear Stearns	3	1.25	Α	4	Α	4
Providan Financial	5	1.9	C++	2.67	В	3
MBNA	3	1.55	A+	4.33	A+	4.33
Citigroup	3	1.45	Α	4	A+	4.33
JPMorgan Chase	3	1.5	B+	3.33	В	3
Morgan Stanley	3	1.7	A+	4.33	A-	3.67
Principal Financial Group	2	1	B++	3.67	NR	
Bank of New York	3	1.3	Α	4	A-	3.67
E*Trade Financial	3	2.05	B+	3.33	B-	2.67
Mellon Financial	3	1.35	B++	3.67	A-	3.67
Federated Investors	2	0.95	Α	4	B+	2.67
State Street	3	1.35	Α	4	A	4
Charles Schwab	3	1.8	Α	4	B+	3.33
Northern Trust	3	1.45	Α	4	A-	3.67
CIT Group	3	1.35	B+	3.33	NR	
Janus Capital Group	3	1.75	B+	3.33	NR	
Insurance						
Progressive	3	1.05	Α	4	B+	3.33
Chubb	2	1.1	Α	4	B+	3.33
Allstate	2	0.95	Α	4	B+	3.33
AFLAC					Α	4
XL Capital	3	1.05	Α	4	В	3
MetLife	2	1.1	Ä	4	NR	•
Hartford Financial Services Group	3	1.25	B++	3.67	В	3
Prudential Financial	2	1.1	A	4	NR	•
American International Group	3	1.2	Ä	4	A+	4.33
ACE					В	3
Cincinnati Financial	2	0.9	B++	3.67	Α-	3.67
Safeco	3	0.95	B+	3.33	В	3
Ambac Financial Group	2	1.1	A	4	A+	4.33
St. Paul Travelers	3	1.2	B++	3.67	NR	
Aon	3	1.2	A	4	B+	3.33
Jefferson-Pilot	1	0.9	A+	4.33	A+	4.33
Torchmark	2	1	Α	4	Α_	4
Lincoln National	2	1.25	A+	4.33	B+	3.33

NDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Loews	3	1.05	B++	3.67	B-	2.67
MBIA	2	1.15	Ā	4	A+	4.33
UnumProvident	3	1.35	B+	3.33	B-	2.67
Marsh & McLennan	3	1.2	B++	3.67	A-	3.67
Real Estate	Ū	1,6	J	0.01	•	0.01
Plum Creek Timber	2	8.0	B+	3.33	NR	
Simon Property Group	2	0.7	B++	3.67	B+	3.33
Archstone-Smith Trust	3	0.65	B++	3.67	NR	3.00
ProLogis	2	0.65	B+	3.33	B+	3.33
Equity Residential	2	0.75	B+	3.33	B+	3.33
	2			3.33		3.33
Equity Office Properties Trust		0.7	B+	3.33 3	NR	•
Apartment Investment & Mgmnt.	3	0.65	₿	3	В	3
fealth-Care Equipment & Sevices	•		A .	4.00		
UnitedHealth Group	2	0.65	A+	4.33	A	4
Caremark Rx	3	0.9	A	4	B-	2.67
Boston Scientific	3	0.75	B++	3.67	B	3
WellPoint	2	0.75	A	4	NR	
Zimmer Holdings	2	0.75	A	4	NR	
Medtronic	1	0.85	A+	4.33	A-	3.67
C.R. Bard	2	0.75	A	4	B+	3.33
Aetna	3	0.95	A	4	NR	_
St. Jude Medical	3	0.85	B++	3.67	В	3
Humana	3	1	B+	3.33	В	3
Express Scripts	3	1.05	A	4	B+	3.33
Stryker	2	0.7	A	4	B+	3.33
Fisher Scientific Intl.	3	0.8	C++	2.67	B-	2.67
Cigna					B+	3.33
Quest Diagnostics	3	0.9	В	3	B-	2.67
Waters	3	1.05	B+	3.33	В	3
Becton Dickinson	1	0.75	A+	4.33	Α	4
Biomet	3	8.0	Α	4	A-	3.67
Bausch & Lomb	3	1	Α	4	В	3
Guidant	3	0.75	Α	4 .	В	3
Health Management Assoc.	3	0.75	B+	3.33	A-	3.67
AmerisourceBergen	3	0.75	B+	3.33	A-	3.67
HCA	3	0.6	B+	3.33	В	3
McKesson	3	0.85	В	3	В	3
Laboratory Corp. of Amerca Hldgs.	3	0.95	В	3	В	3
Medco Health Solutions	3	nmf	Α	4	NR	
Cardinal Health	3	0.9	Α	4	A+	4.33
iMS health	2	0.95	A+	4.33	B+	3.33
Manor Care	3	0.8	B+	3.33	В	3
Thermo Electron	3	1.1	B++	3.67	B-	2.67
PerkinElmer	3	1.15	В	3	В	3
Hospira	•		_	-	NR	•
Millipore	3	1	Α	4	В	3
Baxter Intl.	2	0.6	/. A+	4.33	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Tenet Healthcare	4	0.8	C++	2.67	С	2
Pharmaceuticals & Biotechnology						
Johnson & Johnson	1	0.65	A++	4.67	A+	4.33
Gilead Sclences	3	1.05	В	3	B-	2.67
Pfizer	1	8.0	A++	4.67	Α	4
Abbot Laboratories					Α	4
Forest Laboratories	3	0.8	Α	4	B+	3.33
Amgen -	2	0.95	A++	4.67	B	3
Genzyme General	3	1.25	B+	3.33	В	3
, Allegran	2 .	0.8	A+	4.33	В	3
Merck	3	0.8	Α	4	A+	4.33
Eli Lilly	2	0.7	A++	4.67	B+	3.33
Bristol-Myers Squibb	3	0.95	Α	4	Ā-	3.67
Wyeth	2	0.85	A+	4.33	В	3
Biogen Idec	3	1.2	B+	3.33	Ċ	2
Watson Pharmaceuticals	3	0.75	Ā	4	В	3
Applied Biosystems Group	3	1.4	Ä	4	В	3
Mylan Laboratories	3	0.65	A	4	· A-	3.67
Schering-Plough	3	0.9	A+	4.33	A-	3.67
Chiron	3	1.15	B++	3.67	B-	2.67
King Pharmaceuticals	3	1.05	B++	3.67	NR	
Medimmune	3	1,25	A+	4.33	C	2
Capital Goods	Ū	1,20	• •		_	_
Paccar	3	1.2	Α	4	B+	3.33
Caterpeillar	2	1.2	Ä	4	B+	3.33
Cummins	3	1.35	B+	3.33	B-	2.67
Deere	2	1.05	A	4	В	3
Danaher	2	1.00	8++	3.67	Ä	4
Eaton	1	1.1	A+	4.33	B+	3.33
3M	,	1, 1	13.	7.00	?	0.00
Rockwell Automation	2	1.1	Α	4	, B+	3.33
United Technologies	1	1.15	A++	4.67	?	0.00
Lockheed Martin	2	0.65	A	4.07	ь. В-	2.67
Illinois Tool Works	2	1.05	Á+	4.33	A+	4.33
Rockwell Collins	3	1.1	B++	3.67	NR	7.00
L-3 Communication Holdings	3	*. 1	D	0.01	NR	
	3	1.1	Α	4	A-	3.67
Masco Ingersoll-Rand	2	1.4	Â	4	Ä	4
Parker Hannifin	3	1.15	B++	3.67	A-	3.67
	1	0.8	A++	4.67	A-	3.67
General Dynamics	· ·		B+	4.67 3.33	А- В+	3.33
Northrop Grumman	3	0.65				
ITT Industries	1	0.9	A	4	B+	3.33
Tyco International	3	1.6	8	3	B-	2.67
Emerson Electric	1	1.1	A++	4.67	Α	4
Dover	2	1.2	A	4	A-	3.67
Raytheon	3	0.75	B+	3.33	B-	2.67
General Electric	1	1.3	A++	4.67	A+	4.33

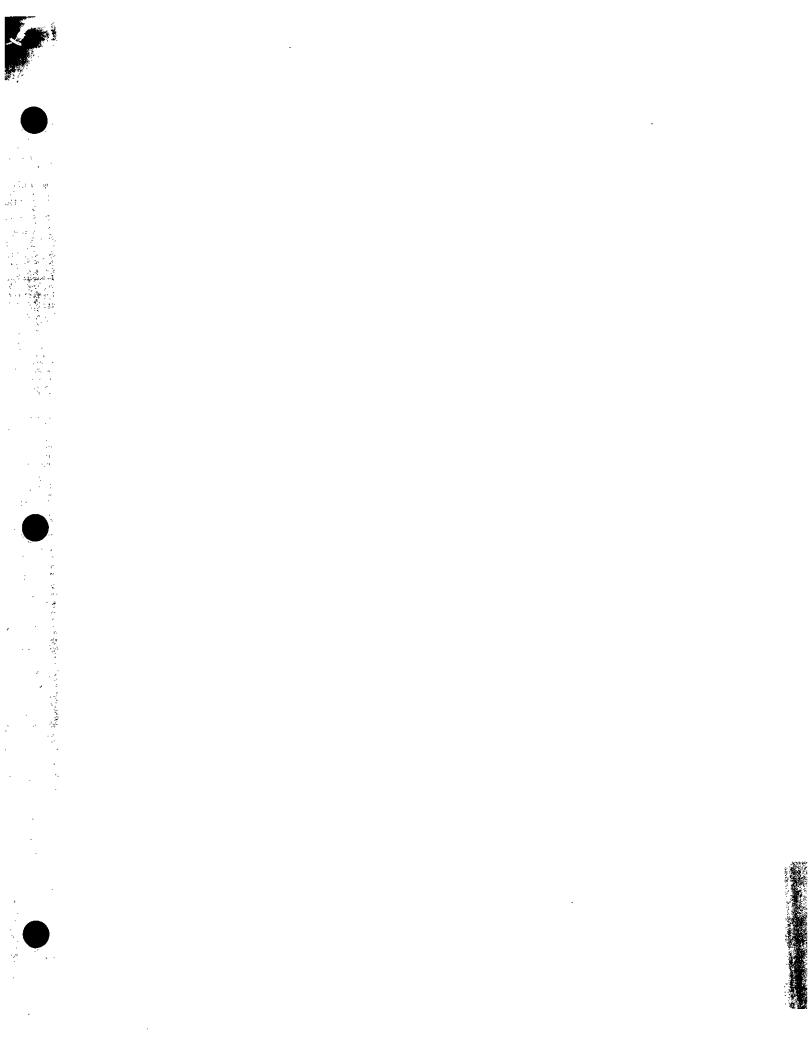
INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Boeing	3	1.05	B++	3.67	B+	3.33
American Standard	3	0.95	B+	3.33	B-	2.67
Cooper Industries.	3	1.2	Α	4	B+	3.33
W.W. Grainger	2	1.15	A+	4.33	A-	3.67
Flour	3	1.2	Α	4	В	3
American Power Conversion	1 '	1.3	B+	3.33	B+	3.33
Textron	3	1.2	Α	4	B+	3.33
Pall	2	1.05	Α	4	В	3
Honeywell International	3	1.3	A+	4.33	В	3
Goodrich	3	1.25	B+	3.33	. B	3
Navistar International	3	1.45	C++	2.67	Ċ	2
Power-One	4 .	2.1	C++	2.67	?	-
Commercial Services & Supplies	·		-		•	
Cendant	3	1.45	8+	3.33	В	3
Apollo Group	3	0.75	Ā	4	B+	3.33
R.R. Donnelley	2	0.95	B++	3.67	В.	3
Robert Half International	3	1.45	A	4	В	3
Waste Management	3	0.95	В	3	В	3
Equifax	3	1.05	В	3	B+	3.33
Monster Worldwide	4	1.95	В	3	B-	2.67
H&R Block	3	1.1	Ā	4	A-	3.67
Avery Dennison	2	0.95	Â	4	A	4
Pitney Bowes	2	0.9	Ä	4	A-	3.67
Cintas	3	1.1	B++	3.67	A+	4.33
Allied Waste Industries	4	1.2	C++	2.67	Ĉ	2
Transportation	-7	1.2	•	2.01	J	_
FedEX	3	1.1	B++	3.67	B+	3.33
United Parcell Service	1	0.8	A+	4.33	NR	0.00
Norfolk Southern	3	1.05	В	3	В	3
Burlington Northern Santa Fe	3	0.95	B+	3.33	A-	3.67
Ryder System	3	1.1	B++	3.67	В	3.07
CSX	3	1. 1	B++	3.67	B-	2.67
Union Pacific	3	0.9	B+	3.33	B	3
Southwest Airlines	3	1.15	B+	3.33	_	3. 6 7
Delta Airlines	3	1. 15	D T	3.33	A- C	3.67
Software & Services					C	2
Yahoo!	3	1.9	B+	3.33	В-	2.67
Autodesk	3	1.2	B++	3.53 3.67	В-, В	3
Adobe Systems	3	1.2		3.07	B+	3.33
Symantec	2	1.05	B++	3.67		
Electronic Arts	3 3	1.05	A+	4.33	В	3
Microsoft					B+	3.33
	2	1.15	A++	4.67	B+	3.33
First Data	2	1	A+	4.33	A	4
Oracle	3	1,3.	A+	4.33	В	3
Fiserve	3	1.1	B++	3.67	B+	3.33
Mercury Interactive	3	1.85	8+	3.33	В	3
SunGard Data Systems	3	1,1	Α	4	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str	Stk Rank		
Computer Sciences	3	1.1	A	4	B+	3.33
Citrix Systems	3	1.8	B++	3.67	B+	3.33
Paychex	3	1.15			A+	4.33
Veritas Software	3	1.7	B++	3.67	B-	2.67
Automatic Data Processing	1	0.95	A++	4.67	A+	4.33
Affiliated Computer Services	3	1.1	Α	4	B+	3.33
Intuit	3	1,15	A	4	B-	2.67
Novell	4	1.6	В	3	C	2
Parametric Technology	5	1.55	C++	2.67	C	2
Sabre Holdings	3	1.4	B+	3.33	В	3
Computer Associates Intl.	3	1.7	В	3	B-	2.67
Electronic Data Systems	4	1.5	В	3	В	3
Compuware	4	1.55	B	3	NR	•
BMC Software	3	1.5	B++	3.67	C	2
Convergys	3	1.4	B++	3.67	NR	-
Unisys	4	1.4	C++	2.67	B-	2.67
Siebel Systems	3	1.85	B++	3.67	B-	2.67
Semiconductors & Semiconductor Eq	-	1.00	.	0.07	0-	2.07
Intel	3	1.4			Α	4
Applied Materials	3	1.55	Α	4	B-	2.67
Texas Instruments	3	1.55	A+	4.33	B	3
Maxim Integrated Products	3	1.65	A.	4.00	B+	3.33
Altera	3	1.65	B+	3.33	В	3.33
National Semiconductor	3	1.4	B+	3.33	B-	2.67
Analog Devices	3	1.75	B++	3.67	B	3
Linear Technology	3	1.75	Α	4	A	4
Xilinx	3	1.8	B++	3.67	B	3
KLA-Tencor	3	1.6	B+	3.33	В	3
Broadcom	3	1.85	B++	3.67	C	2
NVIDIA	3	1.00	Втт	3.07	B-	2.67
Advanced Micro Devices	•				C	
	4	4 75	C	2.67		2 2
Micron Technology	4	1.75	C++	2.67	C	
Novellus Systems	3	1.65	Α	4	B-	2.67
Freescale Semiconductor		4.0=	_	•	NR	•
Teradyne	4	1.95	В	3	C	2
PMC-Sierra	5	2.3	C++	2.67	Ç	2
Applied Micro Circuits	4	2.1	В	3	NR	_
LSI Logic	4	2.05	₿	3	С	2
Technology Hardware & Equipment	_		:		_	_
Qualcomm	3	1,15	A	. 4	В	3
Apple Computer	3	1.05	A	4	В-	2.67
Dell	3	1.2	A++	4.67	8+	3.33
Cisco Systems	3	1.45	A++	4.67	B+	3.33
Network Appliance	4	1.95	B+	3.33	В	3
Hewlett-Packard	3	1.4	A+	4.33	A-	3.67
Lexmark International	3	1.15	B++	3.67	B+	3.33
Motorola	3	1.3	B+	3.33	B+	3.33

NCR 3	Stk Rank			Fin Str	Beta	Safety	INDUSTRY/Company	
IBM		В				3	Jabil Circuit	
EMC Xerox 3 1.55 A 4 Xerox 3 1.45 B 3 Avaya 4 1.3 B 3 N Qlogic 3 1.9 A 4 Molex Sclentific-Atlanta 3 1.4 B+ 3.33 8 Symbol Technologies 3 1.5 B+ 3.33 8 Andrew 3 1.4 B+ 3.33 8 Sanmina-SCI 4 1.85 C++ 2.67 8 Angilent Technologies 3 1.6 B++ 3.67 8 Agilent Technology 4 1.85 C++ 2.67 8 Agilent Technology 4 1.85 C++ 2.67 8 Solectron 4 1.8 B+ 3.33 6 Corwing 4 1.5 C++ 2.67 8 ADC Telecommunications Lucent Technologies 5 1.65 C+ 2.33 8 Sun Microsystems 4 1.6 B 3 Tellabs 3 1.4 B+ 3.33 6 Sun Microsystems 4 1.6 B 3 Tellabs 3 1.4 B+ 3.33 6 Gateway 4 1.3 C++ 2.67 6 JDS Uniphase 4 1.65 C++ 2.67 6 JDS Uniphase 4 1.65 C++ 2.67 6 Junited States Steel 3 1.35 B++ 3.67 8 Materials Materials Materials Nucor 3 1.25 A+ 4.33 8 Phelips Dodge 3 1.25 A+ 4.33 8 Dow Chemical 3 1.15 B++ 3.67 8 Ball 3 0.9 B++ 3.67 8 Dow Chemical 3 1.15 B++ 3.67 8 Delips Dody 3 1.15 B++ 3.67 8 Praxair 3 1.15 B++ 3.67 8 Praxair 3 1.4 B 3 Praxair 3 1.4 B 3 Praxair 3 1.4 B 3 Rohm & Haas 3 1.15 B++ 3.67 8 Rohm & Haas 3 1.15 B++ 3.67 8 DuPont 1 1 A 4 Pupont 1 1 A++ 4.67 Sigma-Aldrich 2 0.8 A 4		B-		B+			NCR	
Xerox		A-	4.67	A++			IBM	
Avaya Qlogic 3 1.9 A 4 E Molex 3 1.3 A 4 Scientific-Atlanta 3 1.4 B+ 3.33 Symbol Technologies 3 1.5 B+ 3.33 Andrew 3 1.4 B+ 3.33 Sanmina-SCI Tektronix 3 1.3 B+ 3.67 Agilent Technologies 3 1.6 B++ 3.67 Converse Technology 4 1.65 B Solectron 4 1.8 B+ 3.33 Corning ADC Telecommunications Lucent Technologies 5 1.65 C+ 2.67 ADC Telecommunications Lucent Technologies 5 1.65 C+ 2.33 Sun Microsystems 4 1.6 B 3 Tellabs 3 1.4 B+ 3.33 Gateway 4 1.3 C++ 2.67 Ciena 5 1.85 C+ 2.33 Naterials Nucor Phelps Dodge 1 1.65 C+ 2.33 Naterials Nucor Phelps Dodge 3 1.25 B+ 3.67 United States Steel 3 1.35 B++ 3.67 United States Steel 3 1.35 B++ 3.67 Weyerhaeuser 3 1.15 B++ 3.67 Weyerhaeuser 3 1.15 B++ 3.67 Ball Louislana-Pacific 3 1.4 B 3 Newmont Mining 3 0.45 B 3 PPG Industries 2 1.1 A 4 Praxair Air Products & Chemicals Rochm & Haes 3 1.15 B++ 3.67 Rohm & Haes 3 1.15 B+ 3.67 Rohm & Haes 3 1.15 B		В	4	Α	1.55	3	EMC	
Qlogic 3 1.9 A 4 E	В 3	В	3	В	1.45	3	Xerox	
Qlogic 3	NR	NR	3	В	1.3	4	Avaya	
Molex 3 1.3 A 4 A Scientific-Atlanta 3 1.4 B+ 3.33 A Symbol Technologies 3 1.5 B+ 3.33 B Andrew 3 1.4 B+ 3.33 E Sanmina-SCI 4 1.85 C++ 2.67 C Tektronix 3 1.3 B++ 3.67 B Agilent Technologies 3 1.6 B++ 3.67 N Converse Technology 4 1.65 B 3 Solectron 4 1.8 B+ 3.93 6 Corning 4 1.5 C++ 2.67 6 ADC Telecommunications Internal Technologies 5 1.65 C++ 2.67 6 ADC Telecommunications Internal Technologies 5 1.65 C++ 2.67 6 Sun Microsystems 4 1.6 B 3 3 6 Sun Microsystems 4 1.6 C+ 2.33 6	3.33	B+	4	Α	1.9	3		
Symbol Technologies 3 1.5 B+ 3.33 B Andrew 3 1.4 B+ 3.33 B Sanmina-SCI 4 1.85 C++ 2.67 C Tektronix 3 1.3 B++ 3.67 B Agilent Technologies 3 1.6 B++ 3.67 N Converse Technology 4 1.65 B 3 Solectron 4 1.8 B+ 3.33 C Corning 4 1.5 C++ 2.67 C ADC Telecommunications Lucent Technologies 5 1.65 C+ 2.33 C Lucent Technologies 5 1.65 C+ 2.33 C C 2.33 C Sun Microsystems 4 1.6 B 3 3 1.4 B+ 3.33 G Tellabs 3 1.4 B+ 3.33 G G C 2.67 G G JDS Uniphase 4 1.65 C+ 2.67 G<	A- 3.67	A-	4	Α	1.3	3		
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Ciena 5 1.85 C+ 2.33 N Iaterials Nucor 3 1.25 A+ 4.33 Phelps Dodge 3 1.25 B++ 3.67 I United States Steel 3 1.35 B++ 3.67 I Dow Chemical 3 1.15 B++ 3.67 I Weyerhaeuser 3 1.15 B++ 3.67 I Ball 3 0.9 B++ 3.67 I Louisiana-Pacific 3 1.4 B 3 I Newmont Mining 3 0.45 B 3 I PPG Industries 2 1.1 A 4 Praxair 3 1 B++ 3.67 I Air Products & Chemicals 2 0.95 B++ 3.67 I Rohm & Haas 3 1.15 B+ 3.33 I Ecolab 2 0.9 B++ 3.67 DuPont 1 1 A++ 4.67 <t< td=""><td></td><td>. Č</td><td></td><td>_</td><td></td><td></td><td>•</td></t<>		. Č		_			•	
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DuPont 1 1 A++ 4.67 Sigma-Aldrich 2 0.8 A 4 A	A 4							
Sigma-Aldrich 2 0.8 A 4	B 3							
- - •		A+				•		
Alcoa 3 I.H A 4 I		B+					——————————————————————————————————————	
•••								
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NDUSTRY/Company	Safety Beta Fi		Fin Str	Fin Str		Stk Rank	
Temple-Inland	3	1.2	B+	3.33	В	3	
Vulcan Materials	1	1.05	Α	4	A-	3.67	
International Paper	3	1.15	B+	3.33	B-	2.67	
Englehard	2	1.05	B++	3.67	B+	3.33	
Sealed Air	3	8.0	В	3	NR		
Pactiv	3	0.85	B+	3.33	NR		
MeadWestvaco	3	1.1	В	3	B-	2.67	
Great Lakes Chemical	3	1.05	B+	3.33	В	3	
Hercules	3	1	В	3	B-	2.67	
Monsanto	3	0.9	B	3	NR	,	
elecommunication Services	•	0.0			14,1		
Nextel Communications	4	1.75	B+	3.33	B-	2.67	
Verizon Communications	3	1	A+	4.33	В	3	
Sprint	3	1.1	В	3	В	3	
Alitei	2	1	A	4	B+	3.33	
CenturyTel	3	1.1	B++	3.67			
BellSouth	2	1.1		3.67 4.33	A	4	
SBC Communications	2	1.05	A+		Α-	3.67	
Citizens Communications	3		A+	4.33	B+	3.33	
	3	1	В	3	B-	2.67	
AT&T	-	4 7	٥.	0.00	B	3	
· Qwest Communications Intl. Itilities	5	1.7	C+	2.33	С	2	
-	•	0.0			_	_	
Constellation Energy Group	2	0.9	A	4	В	3	
PG&E	4	1.05	C++	2.67	В	3	
Sempra Energy	2	0.95	_A	4	8	3	
Dominion Resources	2	0.85	B++	3.67	B+	3.33	
Exelon	2	0.7	Α	4	B+	3.33	
AES					С	2	
Entergy	2	0.75	Α	4	8+	3.33	
FirstEnergy	3	0.75	B+	3.33	B+	3.33	
FPL Group	1	0.7	A+	4.33	A-	3.67	
PPL	3	0.95	B+	3.33	В	3	
Southern	2	0.65	B+	3.33	A-	3.67	
KeySpan	2	0.8	B++	3.67	В	3	
Ameren	1	0.75	A+	4.33	A-	3.67	
Public Service Enterprise Group	3	0.85	B+	3.33	B+	3.33	
American Electric Power	3	1.15	B++	3.67	В	3	
Progress Energy	2	0.8	B++	3.67	B+	3.33	
Duke Energy	3	1.1	B++	3.67	B+	3.33	
NiSource	3	0.8	B+	3.33	8	3	
TXU	3	1	В	3	В	3	
DTE Energy	3	0.7	B+	3.33	B+	3.33	
Edison International	4	1.05	C++	2.67	В	3	
Consolidated Edsion	1	0.6	A++	4.67	B+	3,33	
CINergy	2	0.85	A	4	B+	3.33	
				7	٠ ت	J.JJ	
Xcel Energy	2	0.8	B++	3.67	В	3	

INDUSTRY/Company	Safety	Beta	Fin Str	Stk Rank		
Pinnacle West Capital	1	0.85	A	4	Ā	4
Peoples Energy	1	0.8	Α	4	В	3
Alleghemy Energy	4	1.65	C++	2.67	С	2
Nicor	2	1.05	Α .	4	В	3
Calpine	5	2.25	C+	2.33	В	3
CMS Energy	4	1.35	C++	2.67	С	2
Dynergy	5	2.5	С	2	С	2
Teco Energy	3	0.9	В	3	В-	2.67
AVERAGE	2.67	1.11	B++	3.69	B+	3.29



DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Cost of Service Studies, Rate Increase Distribution, Rate Design & Tariff Issues.

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7		DIRECT TESTIMONY OF MICHAEL L. BROSCH
2	Q.	PLEASE STATE YOUR NAME.
3	Α.	My name is Michael L. Brosch.
4		
5	Q	HAVE YOU SUBMITTED TESTIMONY IN THE INSTANT PROCEEDING ON
6		BEHALF OF THE DIVISION OF CONSUMER ADVOCACY, HEREINAFTER
7		REFERRED TO AS CONSUMER ADVOCATE OR CA?
8	A.	I am sponsoring testimony as CA-T-1 in the instant proceeding, including a
9		discussion of the revenue requirement, as documented within CA-101, and
10		several ratemaking adjustments that I sponsor in that Exhibit.
11		
12	Q.	WHAT IS THE PURPOSE OF THE TESTIMONY THAT YOU ARE NOW
13		SPONSORING?
14	A.	As previously stated in CA-T-1, I am also responsible for reviewing the
15		Company's Cost of Service Study (COSS), revenue increase distribution and
16		proposed rates in the instant proceeding. As a result, this testimony will
17		address the results of my review, including recommendations regarding the
18		allocation of the costs among customer classes, the distribution of revenue
19		increases among customer classes and the design of rates that are intended
20		to generate the Consumer Advocate's revenue requirement for the 2006 test
21		year. This testimony is therefore organized into three sections:

1		I. Class Cost of Service Allocations
2		II. Revenue Distribution Among Customer Classes
3		III. Tariffs and Rate Design
4		
5	l.	CLASS COST OF SERVICE ALLOCATIONS.
6	Q.	DID THE COMPANY PREPARE ANY COST OF SERVICE STUDIES IN THIS
7		DOCKET?
8	A.	Yes. Mr. Young (HECO T-20) has prepared embedded and marginal cost of
9		service studies ("COSS") that are summarized in Exhibits HELCO-2001
10		through HECO-2012. The embedded class cost of service study assigns
11		responsibility among each customer class for the test period overall cost of
12		service using actual "embedded" accounting costs, so as to estimate the
13		relative rates of return being earned by serving each class at present and
14		proposed rates. HELCO's embedded COSS is prepared on the same basis
15		that revenue requirement is determined, including all of the estimated test year
16		rate base and pro-forma O&M expenses asserted by the Company that are
17		the subject of Consumer Advocate ratemaking adjustments.
18		
19	Q.	ARE COST OF SERVICE STUDIES USEFUL IN A RATE CASE DOCKET?
20	A.	Yes. While not the only consideration in setting utility rates, COSS information
21		is useful as a guide for the Commission's decision regarding how much of the
22		overall revenue change in this Docket should be attributed to specific

customer classes and rates. Exhibits HELCO-2001 through HELCO-2006 summarize class revenue requirement and class rate of return data in different formats for this purpose. An additional purpose for conducting embedded cost of service studies is to evaluate "unit costs," which divide allocated costs per unit of demand, energy or by customer, and can be used as a guide to rate design analysis after revenue distribution decisions have been made (see HELCO-2008 and HELCO-2010).

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The other type of cost study performed by Mr. Young (see HELCO-2012) is an evaluation of "marginal costs," which considers the cost associated with serving an additional or "marginal" customer, the next unit of energy or another unit of demand at differentiated points in time. This type of study does not rely upon actual recorded or projected accounting costs, but instead is based upon more theoretical analyses of the rates of change in energy costs on a time differentiated basis, as well as the expected cost of a "next" unit of generating, transmission or distribution capacity. The results of marginal cost studies are useful in considering how to design specific rates and tariffs that are more economically efficient, with an awareness of how costs and pricing revenues may interact to influence customer behavior and However, marginal cost of service studies are not utility profitability. reconcilable to the overall revenue requirement for the test year, which limits their usefulness in setting rates. The Company's embedded cost of service study is a primary cost basis for HELCO's present and proposed rates, and 1 the marginal cost study is one of the Company's considerations in the rate desian.1 2

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4 Q. WHAT GUIDANCE DOES THE HELCO EMBEDDED COST OF SERVICE 5 STUDY PROVIDE REGARDING HOW ANY REVENUE INCREASE IN THIS 6 PROCEEDING SHOULD BE DISTRIBUTED AMONG CUSTOMER 7 CLASSES?

HELCO's embedded cost of service study ("COSS") provides an estimate of class return levels at present and proposed rates that are summarized in Exhibit HELCO-2001. At present rate levels and with all of HELCO's ratemaking proposals, the overall business is calculated to be earning an overall Rate of Return ("ROR") of only 4.10 percent at "Present Rate" levels. Relative to this overall ROR, the Residential Class served on rate "Schedule R" is estimated to be contributing an ROR of only 1.85 percent, or about 45 percent of the overall average ROR of 4.10 percent. Thus, the Company's study would suggest that Schedule R residential revenues should be increased more than the system average percentage increase in order to move closer to the system average estimated "cost of service" for Schedule R. Similarly, the lighting customers on Schedule F are shown to be contributing a below average ROR and would require a higher than average percentage revenue increase to move toward indicated cost of service.

HELCO T-20, pages 13-14.

Conversely, the Company's COSS study at the HELCO asserted revenue requirement level indicates that all of the commercial rates (Schedules G, H, J and P) are estimated to be contributing above-average RORs at present rates, with the Schedule G return nearly double the system average ROR. If accepted as presented, the Company's COSS study would support below average rate increases for the commercial customer classes and particularly Schedule G in order to move closer to the system average ROR (closer to cost of service). However, with the Consumer Advocate's much different revenue requirement and underlying accounting adjustments, the Consumer Advocate's embedded cost of service results are significantly different from the Company's, as discussed more fully herein.

Α.

Q. WHAT DOES THE COMPANY'S EMBEDDED UNIT COST OF SERVICE REVEAL WITH RESPECT TO RATE DESIGN?

As noted previously, properly constructed class cost of service allocations can also be used to indicate approximate demand cost levels per kilowatt ("kw"), energy cost levels per kilowatthour ("kwh") and customer cost levels per customer within each class. HELCO-2008 and HELCO-2010 summarize the estimated Unit Cost Components by Rate Class using HELCO's revenue requirement assumptions and embedded cost allocation methods at proposed rates and at equalized class return levels, respectively. These calculations can normally be useful to compare rate elements within individual tariffs, such

as customer charges, demand charges and energy rates, to the underlying calculated per unit cost to provide service. However, the usefulness of this data is limited because many customers other than large commercial customers are not demand metered, such that demand related unit costs must be recovered through the kwh energy charges in the tariff.

It should also be noted that HELCO's embedded COSS calculations seriously distort unit costs because of the excessive revenue requirement proposed by the Company and because of questionable cost allocation methods that are being used. In particular, the "Unit Customer Costs" are overstated because HELCO has classified large amounts of the fixed costs of distribution poles, lines and transformers as Customer Costs, even though the existence of customers does not really drive the level of such costs. Thus, HELCO's "Unit Customer Cost" calculations must be discounted in any evaluation of rate design parameters.

- Q. ASIDE FROM DIFFERENCES IN OVERALL REVENUE REQUIREMENT, IS

 THE COMPANY'S EMBEDDED COSS BASED UPON REASONABLE

 METHODS AND PROCEDURES?
- 19 A. Except for two methodology issues and several mechanical errors, yes it is.
 20 The Company's study employs a traditional approach in which costs are first
 21 functionalized into production, transmission, distribution and customer-related
 22 categories. Once functionalized, the costs are next classified as demand,

1 energy, or customer driven, and then are allocated among customer classes 2 by applying allocation factors to the functionalized costs.² The general 3 procedures employed by Mr. Young are widely accepted and, with only a few 4 exceptions, reasonable for a utility with HELCO's service and cost 5 characteristics.

6

7 Q. HAVE YOU PREPARED AN EMBEDDED COST OF SERVICE STUDY THAT 8 COINCIDES WITH THE CONSUMER ADVOCATE'S REVENUE 9 REQUIREMENT CALCULATIONS?

10 A. Yes. CA-501 sets forth the summary results of class cost of service allocations that I have prepared. These calculations employed the Company's COSS model logic, applied to the Consumer Advocate's adjusted test year rate base and income statement values, while reflecting several COSS error corrections and methodology changes that are more fully described herein.³

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² These sequential steps are described at HECO T-20, pages 7 through 12.

³ Because the Consumer Advocate employed the HELCO Cost of Service model, with certain modifications described herein, the voluminous printed workpapers associated with this effort (See HELCO-WP-2001) are not reproduced in the Consumer Advocate filing, but have been made available to the Company in electronic format.

1	Q.	DID YOUR REVIEW OF THE COMPANY'S ALLOCATION MODEL REVEAL
2		SEVERAL ERRORS THAT REQUIRED CORRECTION?
3	A.	Yes. Several errors in the Company's embedded COSS were discovered, that
4		HELCO has agreed to correct in responding to information requests submitted
5		by the Consumer Advocate. These include the following items:
6		Correction of the C7 allocation factor, to reflect test year bad debts
7		realized from serving each customer class.4
8	٠	Revision of the C8 allocation factor, based upon an updated analysis of
9		customer service expenses. ⁵
10		Correction of input peak demand values for Schedule G customers, to
11		coincide with load study results. ⁶
12		Correction of Schedule G class load factor to 52%, to coincide with load
13		study results. ⁷
14		Correction of Schedule G kilowatthours per kw demand ratio to reflect
15		191.19 kwh/kw, to coincide with load study results.8
16		These errors have all been corrected in preparing CA-501.
17		

See HELCO responses to CA-IR-483 and 447.

See HELCO responses to CA-IR-484 and 447.

⁶ See HELCO responses to CA-IR-225, 485 and 447.

See HELCO responses to CA-IR-225 and 447.

⁸ See HELCO responses to CA-IR-225 and 447.

1 Q. BEYOND THE CORRECTION OF ERRORS, WHAT ARE YOUR CONCERNS 2 REGARDING HELCO'S EMBEDDED COSS STUDY METHODOLOGIES? 3 Α. There are two COSS methodology issues that should be addressed by the 4 First, HELCO has too broadly classified certain electric Commission. 5 distribution plant investment and related expenses to be "customer" related 6 costs that are treated as if such costs are caused by the connection of each 7 customer. In particular, in the HELCO study, distribution poles, lines and 8 transformers are improperly classified as "customer" costs, even though these 9 costs do not vary in proportion to the number of customers being served and 10 should be classified entirely as "demand" costs. 11 The second methodology issue involved non-fuel production operation 12 and maintenance ("O&M") expenses. In the HELCO COSS calculations, all 13 production O&M expenses other than fuel are classified entirely as fixed or 14 "demand" costs, when a portion of such expenses are "variable" and are 15 caused by the kwh of "energy" that is generated. 16 17 Q. WITH REGARD TO THESE TWO METHODOLOGY ISSUES, SHOULD THE 18 COMMISSION RECOGNIZE THAT JUDGMENT IS NECESSARILY 19 INVOLVED IN THE CONDUCT OF ANY EMBEDDED COSS? 20 Α. Yes. Financial and operational data must be analyzed and interpreted by the 21 cost analyst to determine reasonable approaches to the many decisions

involved in defining cost classification and allocation methods that will produce

meaningful results. Thus, there is no single "correct" embedded cost of service study because of the many judgmental decisions that must be made. The methodology changes I propose are intended to improve upon the judgments and estimates employed in the Company's embedded COSS, and are presented as reasonable alternative approaches that should be considered by the Commission. I agree with and have accepted the balance of the Company's embedded COSS methods and procedures, including other classification and allocation issues of greater importance to study results than the two issues that are raised.

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IS THERE A PRIMARY ISSUE FOR WHICH JUDGMENT IS REQUIRED IN THE CONDUCT OF AN ELECTRIC UTILITY EMBEDDED COST OF SERVICE STUDY, WHERE YOU DO NOT DISAGREE WITH HELCO'S APPROACH?

Yes. The single most important judgment in conducting such a study is the selection of the most appropriate production and transmission demand-related cost allocation factor. For this allocation factor, HELCO has employed an Average and Excess Demand ("AED") allocation that weights together peak demand data and average demand data, so as to recognize that production and transmission costs are incurred by HELCO to meet customer demands during peak periods, as well as throughout the balance of the year (average demands). The AED allocation approach is well suited to HELCO, given the

Company's relatively high system load factor and non-seasonal demand characteristics. Load factor is the ratio of average demand divided by the product of peak demand times all hours in the period and is an indication of how much of the time demand levels are relatively high in relation to peak demands.

I concur in the use of the AED allocation approach for production and transmission demand cost allocations, but, as noted previously, there are certain other methodology improvements that should be applied to HELCO's COSS to better determine the costs incurred to provide service to each customer class.

Α.

Q. PLEASE EXPLAIN THE FIRST PROBLEM WITH HELCO'S EMBEDDED
COSS THAT SHOULD BE ADJUSTED?

HELCO's embedded COSS classifies a large portion of the fixed costs associated with the installed network of electric distribution poles, lines and transformers as "customer" driven costs. In addition to these network costs being treated as customer-driven, the costs of facilities that are closest to the customer, including customer service lines and customer meters, are also classified as "customer" costs. The Consumer Advocate agrees with the classification of service lines and meters as "customer" costs, since these facilities and the related expenses incurred to maintain the facilities are

⁹ HELCO's system load factor is approximately 70 percent (HELCO-WP-2001, page 68, note 5).

required to connect and serve discrete customers. However, the overall distribution network of poles, lines and transformers upstream of service lines and meters do <u>not</u> vary directly with the number of customers served and should be classified entirely as "demand," rather than partially as "customer" costs, as proposed by HELCO. The HELCO studies conducted to determine an estimated fraction of poles, lines and transformers to be classified as "customer" driven are inherently unreliable and the theoretical support for such a "customer" classification is weak, at best.

The other methodology problem with HELCO's COSS is that it improperly treats all non-fuel production operations and maintenance expenses as "demand" driven. This classification is appropriate for many of the types of costs incurred to operate and maintain generating units, as explained in my prior testimony (CA T-1). Some non-fuel production O&M costs do, however, vary with KWH output and should therefore be treated as "energy" costs. Ideally, a study would be conducted to determine the actual mix of demand/energy cost drivers for each O&M account. HELCO should conduct such an analysis in support of its next rate case filling and embedded COSS. In the absence of such a detailed study, I have employed the Federal Energy Regulatory Commission ("FERC") predominance method to evaluate each production O&M account classification, to determine either an energy or demand classification, based upon whether the predominance of costs in the account vary with energy output levels.

1	Q.	TURNING FIRST TO THE DISTRIBUTION NETWORK CLASSIFICATION
2		ISSUE, WHAT PORTION OF ELECTRIC DISTRIBUTION POLES, LINES
3		AND TRANSFORMERS ARE DEEMED TO BE DRIVEN BY THE NUMBER
4		OF CUSTOMERS AND THUS CLASSIFIED AS CUSTOMER COSTS IN
5		HELCO'S EMBEDDED COSS?
6	Α.	The HELCO embedded COSS assumes that the following percentages of
7		distribution network costs are caused or influenced by the number of
8		customers being served, with the reciprocal of these percentage values being
9		classified as demand-related by HELCO:

Distribution Network Facilities	Customer %
Distribution Poles	38%
Overhead Primary Lines	65%
Overhead Secondary Lines	89%
Underground Conduit	47%
Underground Primary Lines	78%
Underground Secondary Lines	50%
Distribution Transformers	56%
Source: HELCO-WP-2001, pages 82 and 133	

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12 Q. PLEASE EXPLAIN WHY THE CLASSIFICATION OF ANY PORTION OF
13 ELECTRIC DISTRIBUTION POLES, LINES AND TRANSFORMERS AS
14 "CUSTOMER" RELATED COSTS IS CONTROVERSIAL.

15 A. The addition of a new customer simply does not cause these costs to be incurred, because these costs are "network" costs for facilities that are designed and constructed to serve the demands of <u>all</u> customers in a given geographic area. HECO has not shown any positive correlation between the number of customers served and the amount invested in distribution network

facilities. Once pole lines and secondary distribution networks have been built into a given geographical area to serve anticipated total demands in the area, such costs are relatively fixed. The costs that can be clearly shown to vary directly with the connection of a new customer are only those costs that must be added each time a new customer is established – specifically, the costs associated with the service line to the customer and his meter, as well as the related O&M expenses to read meters, conduct billing and provide customer contact services.

HELCO has improperly attributed distribution network costs, including poles, lines and transformers, to the customer-related classification. While this treatment is consistent with certain alternative methods documented within the NARUC Cost Allocation Manual that is relied upon by HELCO, when and if supported by appropriate cost analyses, this practice has proved to be controversial, is not supported by careful analysis of cost causation and has been abandoned by electric utilities in other jurisdictions.¹⁰

Q.

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ACCORDING TO MR. YOUNG AT PAGE 11, "FOLLOWING THE NARUC COST ALLOCATION MANUAL, THERE ARE TWO METHODS USED TO DETERMINE THE DEMAND AND CUSTOMER COMPONENTS OF

For example, Arizona Public Service Company, Public Service Company of Oklahoma and PSI Energy (in Indiana) include only distribution services and meters as "customer" costs, with the balance of distribution network facilities classified as "demand." See footnote 17.

DISTRIBUTION FACILITIES: (A) THE MINIMUM SIZE METHOD, AND (B)
THE MINIMUM INTERCEPT METHOD." WHAT ARE THESE METHODS?

A. These two analytical methods are theoretical studies intended to segregate a

These two analytical methods are theoretical studies intended to segregate a customer versus demand breakdown of distribution network facilities and related costs, if the analyst believes that such network facilities should be allocated in part on a "customer" basis. The "Minimum Size" method is based upon estimation of the costs that might theoretically be incurred if one were to re-build the entire distribution network using only the smallest sized poles, conductors and line transformers that could be employed by the utility. Then, having estimated costs for this theoretical minimum-sized system, it is next assumed that all additional costs actually incurred to build the existing distribution network must have been incurred to "up-size" this minimum-sized system to meet the higher actual demand levels.

The alternative "Minimum Intercept" method cited by Mr. Young attempts to quantify the theoretical costs that might be involved in re-building the distribution network with zero demand serving capability – with all actual costs above this theoretical "zero-sized" system deemed to be demand-related costs. After describing these concepts at page 11, Mr. Young states that "[w]hile HELCO prepared both methods in its cost-of-service study for this proceeding, using recorded distribution plant data for 1976-2004, HELCO used the minimum size method to determine the customer component of

distribution lines and transformers" noting that, "[t]he minimum system results are also shown in HELCO-WP-2001."

3

4 Q. IF THE NARUC COST ALLOCATION MANUAL RELIED UPON BY 5 MR. YOUNG CHARACTERIZES BOTH THE MINIMUM SYSTEM AND THE 6 ZERO INTERCEPT APPROACHES AS ACCEPTABLE METHODS TO ESTIMATE THE CUSTOMER COMPONENT OF DISTRIBUTION FACILITIES 7 8 COSTS, WOULD YOU EXPECT BOTH METHODS TO PRODUCE 9 MEANINGFUL AND CONSISTENT RESULTS? 10 Α. Yes, if the two methods are believed to be reliable, their result should be

A. Yes, if the two methods are believed to be reliable, their result should be comparable. However, when HELCO attempted to prepare calculations under both theoretical approaches, the results were wildly different, as summarized in the following table:

"Customer" % classification	HELCO-WP-2001	Minimum System	Zero Intercept
Distribution Poles	Page 85	38%	7%
Overhead Primary Lines	Page 98	65%	78%
Overhead Secondary Lines	Page 104	89%	-80%
Underground Conduit	Page 114	47%	-4%
Underground Primary Lines Underground Secondary	Page 120	78%	9%
Lines	Page 126	50%	-112%
Distribution Transformers	Page 133, 134	56%	134%

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Mr. Young does not explain in testimony why he elected to employ the "minimum system" calculation results, but it is obvious from his data that he had little choice in the matter, since his negative results in some instances and

1 over 100 percent results in other instances from the zero intercept study are 2 clearly not meaningful. In response to CA-IR-312, part f, the Company stated: 3 Overall, for all plant account categories, the minimum system 4 results were much more reasonable than the zero intercept 5 method results. Several of the zero intercept values are 6 negative, which implies a negative customer-related cost for a 7 hypothetical no-load situation, which is not reasonable. The 8 analysis sought to apply a single method for consistency, and 9 so the more reasonable minimum system results were selected 10 for application in the analysis. 11 12 13 Q. IS HELCO'S SELECTION OF THE MINIMUM SYSTEM APPROACH 14 REASONABLE IN THIS DOCKET? 15 Α. No. While the Company has acknowledged that the zero intercept method it 16 used did not produce credible results, even HELCO's minimum system results 17 are unreasonable in concept and nonsensical in result. This can be seen in 18 the minimum system results that yield a much higher estimated "customer" 19 component for primary and secondary lines than for the poles that carry such 20 lines and in yielding higher "customer" percentages for underground primary

lines than for the conduit surrounding such lines.

1 Q. BEYOND THE CONCEPTUAL PROBLEMS WITH CUSTOMER
2 CLASSIFICATION OF DISTRIBUTION NETWORK COSTS, HAS HELCO
3 ADMITTED PROBLEMS WITH ITS CALCULATIONS OF THE MINIMUM
4 SYSTEM VALUES FOR THE TEST YEAR?

Yes. In response to Consumer Advocate information requests, HELCO acknowledged that its minimum system calculations contain several errors, ¹¹ I have not prepared any corrections for this data because the fundamental concept of classifying distribution network facilities as being caused by the number of customers is flawed and should be rejected by the Commission. Instead of correcting the errors, the Consumer Advocate's COSS presentation avoids the need for unreliable and highly theoretical minimum system studies by treating all distribution network facilities (i.e., poles, lines, conduit, line transformers) with a demand classification, recognizing that such facilities are sized and built to meet localized customer demand levels on an economical basis. The only distribution costs that are directly caused by adding a new customer are the costs closest to the customer -- the meters and service line drops required to physically connect the customer to the network.

Α.

1 Q. WHY IS COST CAUSATION IMPORTANT TO THE ISSUE OF CLASSIFYING 2 DISTRIBUTION NETWORK COSTS? 3 Α. Cost causation is the underlying principle behind cost of service study 4 allocations. The principle states that a customer class should bear 5 responsibility for utility costs in proportion to the levels at which that class 6 "causes" the utility to incur costs. For example, fuel costs are widely 7 recognized as being caused by the production of energy, so such costs are 8 allocated among customer classes based upon an "energy" allocator 9 calculated from the relative amounts of loss-adjustment kwh sales to each 10 class. The same principle requires that the Commission not attribute utility 11 costs to customer classes based upon the relative number of customers in 12 each class unless it has been shown that the existence of a customer or 13 changes in the number of customers served causes such costs to be incurred. 14 15 Q. IF A SINGLE CUSTOMER IS ADDED TO OR REMOVED FROM HELCO'S 16 DISTRIBUTION SYSTEM, WHAT COSTS ARE CAUSED BY THAT 17 CUSTOMER ADDITION/REMOVAL? 18 Α. Each customer is generally served by a discrete meter and service line. 19 These are the distribution facilities that are unique to individual customers and 20 that are caused by the connection or disconnection of specific customers. 21 Thus, meters and services investment and customer accounting/service 22 expenses are properly classified by HELCO as "customer-related" costs and

are allocated based upon weighted customer counts within each class. I believe that the Commission should limit the customer classified costs to those costs that vary directly with the number of customers. Unfortunately, HELCO has reached beyond the costs that actually vary directly with customers that are added or lost, by adopting abstract fictional theories about distribution poles, lines and transformers that assume some fraction of these costs also vary directly with the number of customers being served. There has been no showing by HELCO that it adds poles, distribution lines or transformers in direct proportion to changes in the numbers of customers being served.

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PLEASE ELABORATE UPON HOW THE MINIMUM SYSTEM THEORY USED BY HELCO DETERMINED THAT 38 PERCENT OF THE TOTAL COST OF ALL INSTALLED POLES IN THE DISTRIBUTION NETWORK IS CAUSED BY AND SHOULD BE CLASSIFIED FOR ALLOCATION BASED UPON THE NUMBER OF CUSTOMERS BEING SERVED BY HELCO.

16 Α. The minimum system study for poles is set forth at HELCO-WP-2001, 17 page 85. It shows that the smallest sized pole is 25 feet and the estimated 18 replacement cost of these smaller poles is \$663.21 each. In comparison to all 19 39,205 installed poles in HELCO's distribution network, there are only 20 of 20 these "minimum system" poles. The \$663.21 replacement cost estimated for a 21 25-foot pole represents 38 percent of the average replacement cost of 22 \$1,737.66 each for poles of all sizes in the network. Based upon this relationship, HELCO has assumed that 38 percent of the investment and expenses related to poles should be allocated among customer classes based upon the relative number of customers in each class. Since residential customers are 61,373 (or about 83 percent) of the total customer count of 74,174, the 38 percent "customer" component of pole costs is predominantly allocated to residential customers. The other 62 percent of pole costs are classified as "demand" related and are allocated based upon noncoincident demand percentages, resulting in a much lower percentage allocation to the residential class. The other forms are classified as "demand" related and are allocated based upon noncoincident demand percentages, resulting in a much lower percentage allocation to the

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- 11 Q. WHAT IS THE SIGNIFICANCE OF ASSUMING A 25-FOOT POLE IS

 12 REPRESENTATIVE OF THE THEORETICAL MINIMUM SYSTEM?
- 13 A. The fictional concept the Commission is asked to accept is that HELCO could
 14 rebuild its entire distribution system using only 25 foot poles and such a
 15 theoretical system would be indicative of the network (and costs) needed to
 16 connect all of the customers, as long as no customer exerted any electrical
 17 demand upon this hypothetical system that would require the system to be

The actual customer allocation factor used is slightly reduced by weighting factors to recognize somewhat higher costs associated with primary and secondary line investments to serve larger customers, as shown in derivation of the "C1" and "C2" allocation factors at HELCO-WP-2001, page 67, but the resulting percentages to the residential class are very close to the un-weighted "C10" customer allocation factor of 82.742 percent.

The primary and secondary distribution costs that are classified as "demand" related are allocated using the "D2" and "D3" factors shown near the bottom of HELCO-WP-2001, page 68.

"up-sized" beyond the minimum system. It is next asserted, under minimum system theory, that all the additional incurred costs for poles (the other 62 percent of costs) must be caused by the demands actually imposed by customers that forced HELCO to use larger than 25-foot poles after making connections with all customers.

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Q. DOES HELCO NEED TO INSTALL A NEW POLE EVERY TIME IT
 CONNECTS A NEW CUSTOMER?

9 Α. No. If a new customer builds a house in an established area that is adjacent 10 to an installed pole line or underground circuit, it may be possible to extend a 11 service drop from an existing pole or transformer. Alternatively, in some 12 instances a single new customer that is not adjacent to existing facilities may 13 require several new poles for a line extension and some of such poles may be 14 taller than the minimum sized pole on the Company's system. Thus. 15 differences in the density and location of customers is much more important to 16 pole investment requirements than the number of customers being served, yet 17 the minimum system theory does nothing to account for density or location. In 18 my opinion, HELCO's 25-foot minimum size pole is not indicative of cost 19 causation for distribution network investment.

1 Q. DOES HELCO USE ANY 25-FOOT POLES FOR NEW INSTALLATIONS AT

2 THIS TIME?

A. No. HELCO-WP-2001 at page 86, shows that only 20 of the 25-foot poles HELCO has designated to indicate the "minimum system" exist and they were all installed prior to 1979. In response to CA-IR-308, the Company explained that, "[I]n 1979, per a joint pole meeting between HELCO, the County of Hawaii, and the telephone company, it was agreed that a minimum 30 ft. pole would be installed in order to provide minimum ground clearances per General Order (G.O.) 6." Thus, the minimum system 25-foot pole used by HELCO is a poor indicator of costs caused by connecting customers at this time. However, if one substituted an assumed 30-foot minimum system pole assumption, the calculated customer classification for poles would increase from 38 percent to 73 percent, 14 indicating how arbitrary this methodology is in attempting to classify network distribution facilities between "customer" versus "demand" cost causation.

HELCO-WP-2001, page 85 indicates an estimated average replacement cost for installed 30-foot poles of \$1,260.25, which is 72.6 percent of the average replacement cost of all installed poles of \$1,737.66.

1 Q. HOW DID MR. YOUNG SPECIFY THE MINIMUM SYSTEM OVERHEAD 2 CONDUCTOR FOR USE IN ESTIMATING THE CUSTOMER 3 CLASSIFICATION OF OVERHEAD LINES? 4 Α. For primary voltage overhead conductors, HELCO-WP-2001 at page 98 5 indicates an assumption that the minimum primary conductor size is 1/0 size 6 aluminum alloy conductor ("AAC") that can serve 245 amps. Using the ratio of 7 replacement cost for this type of conductor, in relation to the average 8 replacement cost estimated for all primary conductor types installed by 9 HELCO, Mr. Young calculates a "customer component" of 65 percent. 10 11 Q. IS THIS TYPE OF PRIMARY CONDUCTOR INDICATIVE OF HOW HELCO 12 WOULD CONSTRUCT A THEORETICAL MINIMUM SIZED SYSTEM TO 13 CONNECT CUSTOMERS HAVING NO DEMAND? 14 A. No. In its response to CA-IR-309, the Company notes that "HELCO's current 15 practice is to install primary overhead conductors 1/0 AAC aluminum or higher, 16 However, HELCO actually has existing installed copper primary overhead 17 conductor that is smaller in size, which are mainly found on the older lower 18 voltage distribution system of 2,400 volts and 4,160 volts." Thus, HELCO's 19 selected minimum system is really much larger than is minimally required to

connect a customer with low demand levels. In this same response, the

Company noted that its selected minimum-sized primary conductor is far

larger than would be needed by a single new customer, stating, "The 1/0 AAC

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primary conductor on the 7,200 volt distribution system will serve approximately 360 single family residences, assuming 4.4KW average test year demand per single phase service."

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Q. IF THE THEORETICAL MINIMUM-SIZED SYSTEM THAT HELCO RELIED
 UPON CAN ACTUALLY SERVE SIGNIFICANT CUSTOMER DEMANDS,
 CAN THIS APPROACH BE A REASONABLE BASIS TO ESTIMATE A
 CUSTOMER COMPONENT OF DISTRIBUTION NETWORK COSTS?

No. The minimum system theoretical approach is flawed in the way it double counts cost responsibility. The minimum-sized distribution system that HELCO is treating as if constructed solely to connect customers is actually capable of serving a large percentage of customer demand, particularly for residential customers. For example, as noted in the preceding answer, a single strand of the so-called "minimum sized" primary overhead conductor is capable of serving about 360 average single-family residences. However, after the cost of the minimum system is largely allocated to the large numbers of residential customers, no credit is given for the demand serving capability when allocation factors are devised and applied to the "demand" component of distribution network costs. Under HELCO's proposed COSS, the residential customer class pays for the majority of the classified "customer" component of the distribution network, which is capable of meeting much of the residential KW demand. Then, residential customers pay again for their share of costs

classified and allocated as a "demand" component based upon their full measured demands. This problem is explained in the NARUC Electric Utility Cost Allocation Manual at page 95:

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment; "Should the minimum size be based upon the minimum size equipment Currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

In its response to CA-IR-314, HELCO confirmed that its minimum sized overhead distribution transformer is 10kvA and that its smallest padmount transformer is 25 kvA, which are capable of serving about two customers or five customers of average load, respectively. However, after classifying the majority of costs for such transformers as "customer" related and allocating costs primarily on a customer count basis, no "demand serving credit" was

given in the COSS for the load serving ability of these transformers, so as to avoid the double counting problem. Similarly, HELCO's selected overhead and underground conductors are sized to serve 245 and 108 amps, respectively, yet no reduction to customer class demands has been made to account for the load serving ability of conductors treated as customer-related.¹⁵

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9 DISTRIBUTION LINES IN ORDER TO CONNECT AND SERVE
10 CUSTOMERS, AS ASSUMED IN HELCO'S CLASSIFICATION OF SUCH
11 COSTS AS A "CUSTOMER" COST?

12 Α. No. Some customers are connected to existing network facilities by merely 13 adding service lines and meters. Adding other customers may require an 14 extension of network facilities, but such extensions are not directly related to 15 the number of customers being served. For example, adding an apartment 16 building or other high-density residential developments may entail minimal 17 new investment in distribution facilities, while adding dozens or hundreds of 18 new customers. The challenges associated with correlating distribution 19 network investment levels for poles, conductors and transformers directly to

the number of customers being served was confirmed in HELCO's responses

HELCO-WP-2001, page 98 indicates 1/0 AAC primary conductor is rated to serve 245 amps and at page 104 the minimum sized 4/3 AL_TPX secondary conductor can serve 100 amps.

to CA-IR-309, part e; CA-IR-310, part e; and CA-IR-313, part g, where reference is made by HELCO to other variables such as longer distribution line voltage drop concerns and the type of load, which tend to also influence distribution network investment levels.

Q. NEAR THE BEGINNING OF THIS TESTIMONY, YOU MENTIONED THAT HELCO SUBMITTED A MARGINAL COST OF SERVICE STUDY ALONG WITH ITS PRIMARY EMBEDDED COSS. WHAT COSTS ARE TREATED AS CUSTOMER-RELATED IN THE COMPANY'S MARGINAL COST OF SERVICE STUDY?

10 SERVICE STUDY?

A. HELCO-WP-2012, page 46, shows that only "Meter Investment" and "Services Investment" are assumed to be caused by adding a new customer under HELCO's "COMPUTATION OF CUSTOMER-RELATED UNIT COSTS." The total customer-related marginal cost for the Residential Class computed on this page is \$265. Mr. Young divides this amount by twelve (months) to derive the unit "Customer Costs" for Schedule R of \$22.08 that is shown at HELCO-2012, page 4. One of the primary reasons why "Customer Costs" shown in HELCO-2012 are much higher in the "Unit Embedded Costs At Equal ROR" column in comparison to the "Unit Marginal Cost" column is the Company's inconsistent definition of the types of costs that are truly caused by adding a new customer. HELCO has overstated customer costs in its embedded COSS by including distribution network costs for poles, lines and

1 conductors, while its marginal COSS properly recognizes that the only electric 2 plant facilities that vary directly with customer additions are meters and 3 services. 4 Q. HAVE ANY RECOGNIZED AUTHORITIES IN THE FIELD OF PUBLIC 5 6 UTILITY REGULATION WRITTEN ABOUT THE COST CAUSATION 7 PROBLEMS CUSTOMER CLASSIFICATION ARISING FROM 8 DISTRIBUTION NETWORK COSTS? 9 Yes. Dr. James C. Bonbright in "Principles of Public Utility Rates" addressed 10 this issue, acknowledging that utilities may attempt to estimate the costs of the 11 hypothetical minimum system, which he characterized as "indefensible" 12 because such costs are not "caused" by the addition of customers to the utility 13 system; nor are they strictly related to the customers' demand: 14 [w]hat this last-named cost imputation overlooks, of course, is 15 the very weak correlation between the area (or the mileage) of a 16 distribution system and the number of customers served by this 17 For it makes no allowance for the density factor 18 (customers per linear mile or per square mile). Our casual 19 empiricism is supported by a more systematic regression 20 analysis in (Lessels, 1980) where no statistical association was 21 found between distribution system costs and number of 22 customers. Thus, if the company's entire service area stays 23 fixed, an increase in number of customers does not necessarily

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ground.

betoken any increase whatever in the costs of a minimum-sized

distribution system. While, for the reasons just suggested, the

inclusion of a minimum-sized distribution system among the

customer-related costs seems to us clearly indefensible, its

exclusion from the demand-related costs stands on much firmer

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For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and perhaps, even more or less directly) with the maximum demand imposed on this system as measured by But if the hypothetical cost of a minimum-sized distribution system is properly excluded from demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.16

- Q. ARE YOU AWARE OF ANY ELECTRIC UTILITIES THAT, UNLIKE HELCO,
 DO NOT CLASSIFY DISTRIBUTION POLES, LINES OR TRANSFORMERS
 AS "CUSTOMER" COSTS IN THE CONDUCT OF EMBEDDED COST OF
 SERVICE ANALYSES?

 Yes. For example, in recent rate case proceedings I was involved in, Arizona
- Public Service Company, Public Service Company of Oklahoma and PSI
 Energy, Inc. classified all distribution poles, lines and line transformers as
 demand-related costs in the COSS studies they filed with the Arizona,

James C. Bonbright (with editions co-authors Albert L. Danielsen and David R. Kamerschen.) "Principles of Public Utility Rates" Public Utility Reports, Inc., 1988 (2nd edition), p. 491-492.

ı		Okianoma and Indiana regulatory commissions." This treatment of all
2		distribution network poles, lines and transformers as demand-related avoids
3		the controversy and allocation distortions associated with the HELCO
4		"customer" classification approach.
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6	Q.	IN HEŁCO'S LAST RATE CASE, DOCKET NO. 99-0207, THE CONSUMER
7		ADVOCATE ALSO CHALLENGED THE COMPANY'S MINIMUM SYSTEM
8		APPROACH AND PROPOSING TO ALLOCATE DISTRIBUTION COSTS ON
9		THE BASIS OF DEMAND RATHER THAN ALLOCATING PARTIALLY
10		BASED ON THE NUMBER OF CUSTOMERS.18 HOW DID THE
11		COMMISSION RESPOND?
12	A.	According to Decision and Order No. 18365 at page 79:
13 14 15 16 17		If the minimum system and zero intercept methods are rejected, no reasonable alternative methodology is provided by the Consumer Advocate. Based on our review, the commission concurs with the methodologies used by HELCO in its classification of distribution plant costs as demand- and

customer-related, in accordance with the NARUC Manual.

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Arizona Public Service Company, Arizona Corporation Commission, Docket No. E-01345A-05-0816, Direct Testimony of David J. Rumolo filed January 31, 2006, page 7; Public Service Company of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 200300076 filed January 23, 2004, Workpaper L-5, page 2, "Classification of Rate Base"; PSI Energy Inc., Indiana Utility Regulatory Commission Cause No. 42359 filed March 28, 2003, Petitioner's Exhibit Z, Testimony of Kent K. Freeman, page 24.

¹⁸ Decision and Order No. 18365, Docket No. 99-0207, pages 78 and 79.

- 1 Q. HAVE YOU OFFERED A REASONABLE ALTERNATIVE METHOD TO
 2 ALLOCATE DISTRIBUTION SYSTEM COSTS?
- 3 Α. Yes. Allocating such costs on the basis of demand is a reasonable alternative 4 under the circumstances. It is an alternative that is routinely accepted in other 5 jurisdictions, as noted above, and solves the intractable problems associated 6 with the Company's minimum system and zero intercept calculations. 7 respectfully submit that the Commission need not feel bound to force-fit a 8 customer classification onto distribution network facilities using the problematic 9 methods described in the NARUC Cost Allocation Manual, when doing so 10 represents little more than what Dr. Bonbright referred to as, "...impelling 11 pressure to fudge their cost apportionments by using the category of customer 12 costs as a dumping ground for costs that they cannot plausibly impute to any 13 of their other cost categories."

1 Q. THE SECOND CONCEPTUAL PROBLEM YOU IDENTIFIED WITH REGARD 2 TO THE HELCO EMBEDDED COSS IS THAT IT IMPROPERLY CLASSIFIES 3 ALL NON-FUEL PRODUCTION OPERATIONS AND MAINTENANCE 4 **EXPENSES** AS "DEMAND" DRIVEN. WHILE SOME **NON-FUEL** 5 PRODUCTION O&M COSTS ARE VARIABLE SINCE THE COSTS VARY 6 WITH KWH OUTPUT AND SHOULD THUS BE TREATED AS "ENERGY" 7 COSTS. PLEASE EXPLAIN THIS ISSUE.

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Production O&M expenses include many types of costs that are relatively "fixed" in nature, meaning the costs exist in order to make generating capacity available and do not vary directly with the amount of energy that is actually generated. For example, the workforce consisting of power plant operators draw the same salary and benefits on a given day without regard as to how much energy is produced by the generators at the station. On the other hand, certain other non-fuel production O&M costs are influenced by the level of plant output, where higher output causes additional wear on moving parts or contributes to the amount of consumable materials used for plant operations. The HELCO embedded COSS ignores this distinction and simply deems all of the more than \$23 million of non-fuel Production O&M expenses as demand related.¹⁹

HELCO-524 indicates test year Other Production O&M proposed by HELCO of \$23,040,000. This amount, when combined with test year purchased power "capacity payments" of \$17,930,000 (See HELCO-548) makes up the \$40,970,200 that is functionalized to "PRODUCTION DEMAND" in the "O AND M TOTAL" column of HELCO-WP-2001, page 29.

1	Q.	DO ALL OF THE COMPANY'S WITNESSES TREAT NON-FUEL					
2		PRODUCTION O&M EXPENSES AS FIXED COSTS ASSOCIATED WITH					
3		GENERATING CAPACITY, RATHER THAN AS VARIABLE COSTS THAT					
4		ARE DRIVEN BY KWH OUTPUT?					
5	A.	No. The Company's filing is inconsistent on this point. For example					
6		Mr. Giovanni sponsors the HELCO test year production O&M expense					
7		forecast and states at page 19 of his direct testimony					
8		Other production O&M expenses have increased as units operate					
9		online more hours and wear faster. Consequently, variable operating					
10		expenses increase in proportion to operating hours and maintenance					

O&M expense labor and non-labor categories."

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In the underlying calculations supporting his test year estimates of these expenses, some test year expense amounts are determined by application of a rate per kilowatthour times test year levels of generation output, which is a clear acknowledgment of the variable nature of some expenses.²⁰ Several of the Company's responses to information requests inquiring into the basis for projected test year production O&M expense reveal

expenses as more wear and tear is experienced. The increase is reflected in

See for example CA-IR-2, Attachment 2A, pages 22-24, where boiler chemicals, demineralizer chemicals and lube oil expenses are estimated using a per MWH algorithm.

the variable nature of the expense, where generation output levels or run-time 2 hours directly impact cost levels.²¹

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Another HELCO witness, Ms. Giang, sponsors the Company's test year estimated fuel expense using P-MONTH simulation software. She notes at T-4. page 25 that one of the "key inputs to the P-MONTH production" simulation model" is "5) variable O&M costs" associated with the HELCO generating units. Thus, for production simulation purposes, HELCO properly recognizes that some of the non-fuel production O&M expenses are variable in nature and consideration is given to such variable O&M costs when simulating economic dispatch, even though Mr. Young treats all of such costs as fixed, capacity related expenses in his embedded COSS. At HELCO-WP-404, page 98, the "Variable O&M \$/MWH net" and "Variable O&M \$/hour" are shown for each HELCO generating unit, as input into P-MONTH. The footnote on this workpaper also indicates that HELCO recognizes that variable production O&M amounts are for use in "HELCO Automatic Generation Control ("AGC") for economic dispatch of the above listed units.

Finally, even Mr. Young's own testimony is inconsistent on this point. The marginal cost of service study that he sponsors explicitly treats a portion of non-fuel production Q&M costs as variable energy-related costs, in contradiction with the treatment of all such costs as fixed capacity-related costs in his embedded cost of service study. At HELCO-WP-2012, page 3,

²¹ See, for example, CA-IR-60 (emission fees) CA-IR-256 (disbursed diesel overhauls).

Mr. Young has included at line 2 "Variable O&M expense (2006 cents/kWh)" with a value of 2.22369 cents per kWh in calculating total estimated marginal energy costs. In response to CA-IR-316 and CA-IR-444, HELCO explained that this amount includes, "[t]he types of expenditures are: Scheduled and Preventative Maintenance, Supplies and Consumables, Chemical Treatment, Demineralization and Fuel Oil Treatment," yet these same expense types are inexplicably treated entirely as fixed costs subject to allocation on a demand basis in the embedded cost of service study.

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Q. HOW SIGNIFICANT IS THIS PROBLEM IN TERMS OF COSS RESULTS?

It may not be possible to precisely quantify the required adjustment because a special study is required to determine the fixed versus variable nature of costs recorded in the Production O&M Accounts. HELCO has not performed such a study.²² However, the impact may be substantial, particularly if the testimony of HECO witness T-6 is accurate in attributing HELCO's recently higher production O&M expenses to the fact that generating units are being operated more heavily.²³ As a point of reference, under the policy approach used by the Federal Energy Regulatory Commission ("FERC") regarding such matters, a significant percentage of electric utility non-fuel Production O&M expenses

See CA-IR-220, part f and CA-IR-438.

See for example, HECO T-6 at pages 8 and 30.

might be re-classified as energy costs. The FERC policy employs a "predominance" method to classify Production O&M in each account whenever special studies have not been prepared by a utility to support more detailed classifications. This methodology looks to the "predominant" cost causative elements in each expense account, and classifies all costs in the entire account based upon whether more than 50 percent of the expenses in the account are relatively "fixed," being driven by the need to maintain availability of capacity, as opposed to being "variable" with the amount of energy that is produced.

I applied the FERC method to HELCO's forecasted 2006 Production O&M expenses in HELCO-WP-101C and the result suggests that a 20% energy, 80% demand classification may be appropriate for the Company. From this estimate, I reclassified approximately \$4.1 million of HELCO non-fuel Production O&M expenses from a "demand" to an "energy" classification to improve upon cost allocations performed by the Company that improperly treated all non-fuel O&M expenses as 100 percent demand-related.²⁴

19 Q. HAS THE CONSUMER ADVOCATE RE-CALCULATED THE EMBEDDED
20 COSS BASED UPON THE CONSUMER ADVOCATE ACCOUNTING

1		ADJUSTMENTS AND RECOMMENDED REVENUE REQUIREMENT					
2		EMPLOYING REVISIONS FOR THE CONCERNS YOU RAISE?					
3	A.	Yes, restatements and corrections have been made for all issues. The					
4		Consumer Advocate has re-calculated HELCO's embedded cost of service					
5		study based upon its proforma adjusted rate base and expense amounts. The					
6		results of this recalculation are set forth in Exhibits CA-500 and CA-501, which					
7		were prepared in the same format as the Company's COSS studies for the					
8		sake of comparability.					
9		·					
10	Q.	DID YOU USE THE COMPANY'S ALLOCATION MODEL TO PREPARE					
11		YOUR REVISED CLASS COST OF SERVICE STUDY SCHEDULES?					
12	A.	Yes. As a matter of efficiency and to aid in comparing the study results, I					
13		linked Mr. Young's spreadsheet model logic into the Consumer Advocate's					
14		accounting schedules to prepare my cost of service Exhibits CA-500 and					
15		CA-501. Aside from changed test period input amounts for revenues, expense					
16		and rate base, the other changes made to the Company's embedded COSS					
17		model are:					
18		Correction of five admitted errors in the Company's COSS calculations,					
19		as summarized in the response to CA-IR-447 for HELCO T-20.					
20		Classification of all distribution network poles, lines and transformers as					
21		demand-related costs.					

Reclassification of approximately 20 percent of non-fuel Production
 O&M expenses from a "demand" to "energy" classification, based upon application of the FERC predominance method.

After making these changes, the resulting class rates of return are generally closer to equality (i.e., each customer class is contributing the same rate of return on rate base). For example, the indicated Residential Rate of Return with these revisions improves to 3.79 percent of the Total System Rate of Return ("ROR"), as shown at the bottom of Exhibit CA-500, page 1. Only the Schedule G General Service customers have an ROR significantly above average, designated as "ROR As % of System ROR."

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Q. SHOULD THE COMMISSION RELY SOLELY UPON CLASS COST OF SERVICE ALLOCATIONS TO DETERMINE THE RATE CHANGES IN THIS CASE?

No. Cost of service results are estimates based upon methods and judgments of analysts that may vary significantly. In addition, cost of service results can change significantly from one test period to another, due to shifts in load conditions, expense levels or methodology changes. Therefore, cost of service results should be used only as a "guide" in the direction rate changes should occur, while other factors must also be considered by the Commission.

1 II. REVENUE DISTRIBUTION AMONG CUSTOMER CLASSES.

Q. DOES HELCO ADVOCATE DISTRIBUTING ITS PROPOSED RATE
 INCREASE OR "RATE SPREAD" AMONG CUSTOMER CLASSES BASED
 UPON ITS COST OF SERVICE ALLOCATIONS?

Yes. HELCO-2004 sets forth the Company's proposed revenue increase distribution that Mr. Young explains at page 5 of HELCO-T-20, based upon a total proposed rate increase of \$29.9 million. The proposed rate increase distribution would increase rate revenues charged to Residential Schedule R and Commercial Schedule G and Schedule H customers by 9.25 percent, which is the average overall proposed increase percentage for all sales revenues. Commercial Schedule J and Lighting Schedule F customers would receive an above-average rate increase, while large commercial customers using Schedule P would receive a below-average increase.

The rationale for HECO's proposed rate increase distribution across rate classes is explained at page 5 of Mr. Young's testimony (HECO T-20):

The proposed allocation follows the guidelines applied in previous dockets, to allocate the proposed revenue increase to rate classes such that each class would move closer to cost of service, as reflected by each class's rate of return moving closer to the system average rate of return. The guidelines are subject to two constraints: First, each rate class is allocated a revenue increase in a reasonable range, which is +/- 25% of the proposed Company average sales revenue increase; and second, each rate class is allocated a revenue increase such that the class rate of return is +/- 50% of the Company average rate of return. If the proposed revenue allocation cannot satisfy

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both guidelines, then the revenue increase at +/- 25% of the proposed Company average sales revenue increase takes priority.

Thus, the Company's approach would appear to balance two objectives, providing gradual movement toward indicated cost of service for each class, while limiting dramatic changes that may "shock" customers or produce unintended revenue impacts by imposition of the 25% variation around the average percentage increase.

11 Q. SHOULD COST OF SERVICE BE THE ONLY DETERMINANT OF
12 ELECTRIC UTILITY RATES?

No. Cost of service allocations are inherently imprecise and dependent upon a multitude of judgments regarding cost causation, as well as imperfect data regarding customer demands and cost classifications. Therefore, cost of service must serve only as a guide and not dictate the distribution of revenue changes among customer classes. It is essential to consider many factors, other than indicated class cost of service results, in determining an appropriate distribution of revenue increases. These other factors include:

Revenue stability for the utility - rates should not be abruptly changed,
 creating a risk that customers may modify their demand levels or
 migrate between rates, producing unexpected revenue impacts.

1		Gradualism in customer impacts - customer understanding and					
2		acceptance of rate changes is dependent upon avoidance of abrupt					
3		monthly bill impacts.					
4		Administrative practicality – rate structures and the relationship					
5		between rates must be rational and simple to apply and understand.					
6		Public policy priorities such as conservation or low-income					
7		assistance - purely cost based rates may fail to meet other desirable					
8		public policy objectives.					
9							
10	Q.	AT THE LOWER REVENUE REQUIREMENT RECOMMENDED BY THE					
11		CONSUMER ADVOCATE, WHAT DISTRIBUTION OF RATE CHANGES DO					
12		YOU RECOMMEND?					
13	A.	The following table indicates the distribution of revenue changes					
14		recommended by the Consumer Advocate, to be implemented in order to					
15		provide the amount of overall revenue increase ultimately ordered by the					
16		Commission:					

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Distribution of CA Proposed Rate Increase

	Spread %	\$000	
Schedule R	43.8%	\$	7,157
Schedule G	7.0%		1,144
Schedule J	34.0%		5,556
Schedule H	1.7%		278
Schedule P	13.0%		2,124
Schedule F	0.5%		82
TOTAL	100.0%		16,341
Power Factor Revision			172
Miscellaneous Charges	<u>-</u>		130
TOTAL REVENUE		\$	16,643

The Consumer Advocate's recommended total revenue increase is proposed to be split between the total amount applicable to the listed sales rate "Schedules," and other separately recommended "Power Factor Revision" and "Miscellaneous Charges" revenue increases that are explained later in this CA-T-5. After accounting for these discrete revenue changes, the "Spread %" values stated above should be used to distribute the intended sales rate revenue increases.

The result of this revenue increase distribution is to gradually move class revenue levels toward cost of service, as indicated by CA-500, page 2, which shows class "Rate of Return Index" at proposed rates assuming the Consumer Advocate recommended distribution of the rate increase.

Q. IF THE REVENUE REQUIREMENT ULTIMATELY FOUND REASONABLE
BY THE COMMISSION IN THIS DOCKET EXCEEDS THE
RECOMMENDATION OF THE CONSUMER ADVOCATE, HOW SHOULD

1		ANY LARGER REVENUE INCREASE BE DISTRIBUTED AMONG					
2		CUSTOMER CLASSES?					
3	A.	The ultimately approved revenue increase should be distributed among all					
4		customer classes based upon the percentage factors set forth above, after					
5		accounting for the growth in Late Payment Fees and the changes to Power					
6		Factor and Miscellaneous Services rates.					
7							
8	111.	TARIFFS AND RATE DESIGN.					
9		A. RESIDENTIAL RATE DESIGN.					
10	Q.	AT PAGES 14 THROUGH 20 OF HIS TESTIMONY, HELCO WITNESS					
11		MR. YOUNG EXPLAINS HELCO'S PROPOSED RATE DESIGN APPROACH					
12		FOR THE SCHEDULE R RESIDENTIAL SALES RATES. HAVE YOU					
13		REVIEWED THAT TESTIMONY?					
14	A.	Yes. Mr. Young sponsors a new inclining block rate structure with modified					
15		minimum bill provisions for Schedule R that would replace the existing HELCO					
16		single-block energy rate if approved by the Commission. His recommendation					
17		is also supported by Dr. Ren Orans (HELCO T-19) who testifies in support of					
18		this type of rate structure for high cost utilities like HELCO, in order to promote					
19		conservation and mitigate rate increase impacts upon lower volume residential					
20		consumers while stabilizing fixed cost recovery from large residential					
21		customers with intermittent use. The new rate structure would retain the					
22		existing \$10.00 per month customer charge (\$14.50 for 3-phase service), but					

would replace the existing single-block energy rate for monthly kwh usage with a three-tiered energy charge having an initial block from 0-300 kwh, a second 3 block from 301-1,000 kwh and a third block for usage over 1,000 kwh.

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DR. ORANS IDENTIFIES AND DESCRIBES WHAT ARE CHARACTERIZED AS EIGHT GENERALLY-ACCEPTED RATE DESIGN CRITERIA THAT ARE USED BY MOST UTILITIES AND REGULATORS AT PAGES 4 AND 5 OF HIS TESTIMONY (HELCO T-19). DO YOU AGREE WITH THESE CRITERIA?

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Α.

The criteria that are presented by Dr. Orens are consistent with the rate design objectives I have observed to be typically addressed in utility rate case proceedings. The listed criteria are broad objectives that are desirable rate design goals, but can be difficult to simultaneously satisfy under specific circumstances. For example, a rate design emphasizing promotion of efficient consumption may conflict with the goal of utility revenue stability to the extent consumers react to pricing cues and reduce demand (and utility revenues). In other instances, rate design simplicity and customer understanding may need to be compromised to place more emphasis upon cost based rates or upon customer bill stability, when more complex tariff structures are required to achieve such goals. Judgment is required to balance the competing rate design goals, assigning proper weight to particular objectives based upon utility specific facts and unique energy market circumstances. Dr. Orens also

1		mentions several HELCO-specific considerations as "additional factors" that					
2		he relied upon in recommending a new inclining block rate structure for					
3		Schedule R, including:					
4		Implementation of an inclining block structure serves to strengthen the					
5		incentive for large residential customers to invest in energy efficiency					
6		measures by offering a stronger price signal to induce conservation.					
7		(T-19, pages 3 and 8.)					
8		HELCO's rising cost of service is mainly due to demand growth caused					
9		by new housing development, such that inclining block rates result in					
10		more equitable cost apportionment to large users who are more costly					
11		to serve. (T-19, pages 6 and 8.)					
12		HELCO's high residential rates are likely to be a burden for many					
13		customers, particularly given the wide gap between lowest and highest					
14		income electricity consumers on the Big Island, making "affordability" an					
15		important criterion, particularly for the portion of electricity needed to					
16		meet a customer's essential needs. (T-19, page 6.)					
17							
18	Q.	DOES THE CONSUMER ADVOCATE SUPPORT IMPLEMENTATION OF					
19		INCLINING BLOCK RATES FOR HELCO RESIDENTIAL SCHEDULE R					
20		SERVICE?					
21	A.	Yes, for this utility with high operating costs and rate levels, an inclining block					
22		rate structure is appropriate. HELCO's high rate structure and the rate					

increases contemplated in this docket undoubtedly represent an economic hardship to ratepayers, particularly those with lower incomes. Inclining block rates represent an alternative rate structure that helps to mitigate the impact of rate increases to customers with smaller homes and kwh usage below 1,000 kwh per month, while assigning above-average rate increases to larger residential consumers. Another benefit of inclining block rates is the provision of somewhat strengthened pricing cues to large users that may stimulate conservation investment among the customers most likely to be financially positioned to afford such investments. The Company's proposal represents a measured initial step toward inclining block rates that is acceptable at this time.

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13 Q. ARE THE INCLINING BLOCK RATES PROPOSED BY HELCO
14 CONSISTENT WITH COST OF SERVICE INFORMATION SUBMITTED BY
15 THE COMPANY?

16 A. Yes. HELCO's marginal cost of service study indicates higher average 17 marginal energy costs for secondary service to residential customers than the 18 embedded unit cost of energy, suggesting that inclining block rates are 19 supported by cost of service evidence.²⁶ In its response to CA-IR-220, the

²⁶

See HELCO-2012, page 4 of 4, where Unit Embedded Demand Costs and Marginal Energy Costs of \$22.29/kw and 17.155 cents per kwh, respectively, are compared to Unit Marginal Demand Costs of \$26.06 and Marginal Energy Costs of 17.55 cents per kwh. If high volume residential customers contribute more heavily to Priority Peak or Mid-Peak periods due to large air conditioner loads, the energy cost difference is more pronounced.

Company notes in support of its inclining block proposal that Section 111(d) of the 1978 Public Utility Regulatory Policy Act ("PURPA") indicates that the energy component of an electric rate may not decrease as kwh consumption by the class increases "except to the extent the utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy components, decrease as consumption increases during such period." While HELCO does not presently have declining block residential energy rates, the compliment to this policy statement under PURPA is that a utility with energy costs that increase as consumption increases should consider implementation of inclining block energy rates.

Α.

Q. ARE THE DIFFERENCES BETWEEN RATE BLOCKS THAT ARE PROPOSED BY HELCO UNDER ITS NEW INCLINING BLOCK STRUCTURE SUBSTANTIAL ENOUGH TO POTENTIALLY CAUSE RATE SHOCK TO ANY LARGE CUSTOMERS?

No, this should not be a problem. HELCO-2018 illustrates at page 1 the customer bill impacts under the inclining block proposal, indicating overall monthly charges at kwh usage levels ranging from 100 kwh to 10,000 kwh. At present rates that have a single block energy rate, the average price per kwh gradually declines as usage increases. Under proposed inclining block rates at HELCO's proposed overall rate increase, this gradual decline in average price per kwh caused by the customer charge is eliminated, while the new

effective average price per kwh is nearly flat across usage levels, as shown in the following table derived from HELCO-2018:

	<u>MONT</u> HL	Y BILL AT:	AVERAGE	CENTS/KWH	PERCENT
KWH	PRESENT	PROPOSED	PRESENT	PROPOSED	INCREASE
300	\$ 94.42	\$ 98.77	31.47	32.92	4.6%
600	\$ 178.84	\$ 193.87	29.81	32.31	8.4%
1,000	\$ 291.40	\$ 320.68	29.14	32.07	10.0%
2,000	\$ 572.80	\$ 646.43	28.64	32.32	12.9%
5,000	\$1,417.00	\$1,623.69	28.34	32.47	14.6%
10.000	\$2,824,00	\$3 252 45	28 24	32 52	15.2%

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Thus, the proposed price differences between the new inclining blocks are modest, resulting in bill impacts that are unlikely to shock customers, particularly when implemented at the Consumer Advocate's lower overall rate increase recommendation. As noted by Mr. Young, the tiers are designed so that most of a typical customer's usage is covered by the first two tiers and only the very highest residential customer usage will incur the third tier energy charges.²⁷

- 1 Q. HAS HELCO MADE SPECIAL PROVISION FOR LOW INCOME
- 2 CONSUMERS IN THE DESIGN OF THE PROPOSED INCLINING BLOCK
- 3 SCHEDULE R RATES?
- 4 A. Yes. Customers receiving bill credits under the State of Hawaii's Low Income
- 5 Home Energy Assistance Program ("LIHEAP") would be billed for energy at
- only the lowest tier of the inclining non-fuel energy blocks of Schedule R.²⁸

- 8 Q. HOW SHOULD AN INCLINING BLOCK RESIDENTIAL RATE BE DESIGNED
- 9 AT THE LOWER REVENUE REQUIREMENT LEVELS BEING PROPOSED
- 10 BY THE CONSUMER ADVOCATE?
- 11 A. At CA-proposed rate increase levels for Schedule R, usage in the first two
- energy blocks up to the 1,000 kwh cutoff should be targeted to receive the
- average percentage revenue increase ultimately ordered for the residential
- 14 class. This is comparable to the approach recommended by Mr. Young for
- these rate blocks under HELCO's rate increase proposal.²⁹ Then, the third
- block rate for usage above 1,000 kwh/month should be priced \$0.8741 above
- the middle block to preserve the block "spread" proposed by HELCO, 30

²⁸ ld. page 15.

²⁹ Id. page 17.

HELCO-2107 proposed rates for the over 1000 kwh block are 15.7427 cents/kwh, versus 14.8686 cents/kwh for the 301-1000 block, for a difference of 0.8741 cents.

1 reducing prices in the initial 0-300 kwh block to yield targeted total residential 2 revenues. 3 4 Q. IN ANOTHER RATE DESIGN POLICY SHIFT, HELCO HAS PROPOSED A NEW SCHEDULE R MINIMUM BILL RATCHET MECHANISM WHICH IS 5 SPONSORED BY MR. YOUNG AND DR. ORENS.31 HOW WOULD THIS 6 7 PROPOSED MECHANISM BE STRUCTURED? 8 Α. According to Mr. Young, the revised Schedule R minimum bill provision would charge the customer the "higher of \$20.00 or the bill calculated based on 15% 9 of the highest kWh usage in the last 11 months."32 The actual mechanics of 10 the calculation are fairly complex, as noted at the bottom of page 17 of 11 12 Mr. Young's testimony: 13 In order to calculate the proposed minimum bill, the customer's 14 highest kWh usage over the past 11 months is identified first. That peak kWh usage is multiplied by 15%, and the resulting 15 16 kWh is billed at the current effective rates, including the 17 appropriate fuel oil adjustment factor and any other surcharges or credits that may be in place. This calculated month's bill is 18 19 compared to \$20.00, and the minimum bill is the higher of the

two amounts. Then the minimum bill is compared to the

customer's regular bill calculated at the current billing month's

minimum bill or the calculated bill for current month's usage.

The customer is assessed the higher of the

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kWh usage.

HELCO T-20, pages 17-18, HELCO T-19, pages 11-12 and 24-27.

³² HELCO T-20, page 17.

Two exceptions are proposed to exclude LIHEAP customers and Net Energy

Metering customers from the alternative minimum bill provisions, as explained

at page 18 of Mr. Young's testimony.

A.

Q. WHY IS HELCO PROPOSING TO ADD THIS ALTERNATIVE CALCULATION
TO ITS SCHEDULE R MINIMUM BILL TARIFF PROVISION?

This multi-step procedure is desired by HELCO in order to, "recover a greater portion of the total fixed costs of serving the residential class." According to Mr. Young, the basic \$20.00 per month minimum charge only recovers about 71 percent of the residential customer-related cost, which is estimated at \$28.06 per month in HELCO-2008, and none of the demand cost." There are a few HELCO residential customers who take relatively large amounts of electric service seasonally or intermittently, but then use less energy and pay much lower monthly bills when their vacation homes are vacant. This new minimum bill ratchet provision appears to be aimed at such customers, producing larger minimum bills to them, based upon prior months' usage, when their homes are temporarily vacant.

³³ T-20, page 17, line 12.

1 Q. HOW MANY CUSTOMERS ARE ANTICIPATED TO BE IMPACTED BY THE
2 ALTERNATIVE MINIMUM BILL PROVISION, RESULTING IN A MINIMUM
3 BILL IN EXCESS OF \$20.00?

A. According to HELCO-2015, which displays the customer impacts of the proposed alternative Schedule R minimum bill ratchet provision, only 2.8 percent of residential customer bills are expected to be impacted by the Company's proposal. In contrast, the existing minimum bill provision already impacts about 2.1 percent of customers, 35 so the scope of the new provision is not significantly broader. However, the dollar impact upon this minority of customers with sporadic high usage may be quite significant, since the changed minimum bill provision is expected to produce \$292,762 in revenues annually, 36 compared to annual revenues of only \$118,700 under the existing minimum bill provision. 37

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HELCO-2015 indicates that 2.8 percent of bills would be minimum billed under the new provision, which translates into 20,272 bills out of a total of 736,476 bills. HELCO-WP-302 at page 5 indicates that the existing minimum bill impacts 15,565 bills annually, which is 2.1 percent of the total.

³⁶ HELCO-WP-302, page 10.

³⁷ HELCO-WP-302, page 5.

1 Q. DOES THE CONSUMER ADVOCATE RECOMMEND IMPLEMENTATION OF 2 THE COMPANY'S PROPOSED ALTERNATIVE MINIMUM BILL PROVISION? 3 Α. No. There are too many tariff complexity, ratepayer equity and customer 4 resistance concerns caused by this proposed tariff modification. I believe that a homeowner reasonably expects to reduce his/her monthly energy bill 5 6 significantly whenever air conditioning and appliances are turned down or off 7 upon vacating his/her home. In fact, such conservation actions by consumers 8 are consistent with energy conservation messages and DSM program 9 objectives advanced by utilities throughout the State. A complex new 10 minimum bill tariff calculation, that may result in large and unanticipated electricity billings at 15 percent of prior month usage for a vacant home, are 11 12 likely to be perceived as punitive, inequitable and may meet with potentially 13 strong resistance from affected customers who do not understand fixed versus 14. variable cost structures of electric utilities and do not expect to pay for energy 15 not delivered.

- 17 Q. IS IT A PROBLEM FOR HELCO TO ONLY RECOVER 71 PERCENT OF ITS
 18 CUSTOMER RELATED FIXED COSTS WHEN THE \$20.00 MINIMUM BILL
 19 IS CHARGED?
- 20 A. Not really. Only about 2 percent of all residential customer bills receive 21 minimum bills and a 71 percent recovery of customer costs is not 22 unreasonable for this minor portion of the customer population. Moreover, as

noted in the cost of service section of this testimony, HELCO has overstated its customer costs through the excessive attribution of distribution network costs to the customer classification by using the minimum system theoretical analysis. Retaining the existing, simple to understand \$20.00 monthly minimum bill already recovers more than the \$12.64 monthly customer costs indicated by the Consumer Advocate's cost of service study, after correction of the customer cost overstatement in the Company's COSS, as shown at CA-501, in the row captioned "TOTAL CUSTOMER" for Schedule R.

Q.

Α.

DEMAND-RELATED COSTS ARE NOT RECOVERED UNLESS A RATCHET PROVISION IS ADDED TO THE SCHEDULE R MINIMUM BILL PROVISION? HELCO's concern on this point is unproven. It is entirely possible for vacant large homes to create a demand reduction that is beneficial to overall system operations, by reducing the need for generation and transmission capacity as well as potentially expensive on-peak fuel costs. If there is diversity in the timing of demand reductions arising from large air-conditioned homes being vacant, HELCO should realize reduced fixed demand-related costs.

Q. WILL THE INCLINING BLOCK RATES THAT HELCO HAS PROPOSED, AND
THAT ARE SUPPORTED BY THE CONSUMER ADVOCATE, INCREASE
THE REVENUES COLLECTED FROM THE LARGEST RESIDENTIAL

HOMES?
TIMES WHEN SUCH CUSTOMERS MAY TEMPORARILY VACATE THEIR
CUSTOMERS, SO AS TO PARTIALLY COMPENSATE THE COMPANY FOR

Yes. This is another reason why the proposed alternative minimum bill may produce unreasonable results. Many of the same customers who will receive the highest rate increases under the inclining block rate structure would also be impacted by higher minimum bills under the alternative 15% minimum bill provision. There are approximately 1,182 customers who would be billed for usage in the proposed highest tier of the non-fuel energy charge and also for the minimum charge under the proposed 5% minimum bill provision, although customers who are billed at the proposed minimum charge are not simultaneously billed at the highest tier non-fuel energy charge. The proposed minimum bill provision adds approximately \$96,886 to customer bills at proposed rates for customers with usages greater than 1,000 kWh per month.³⁸

Α.

1	Q.	HAVE OTHER ELECTRIC UTILITIES ADOPTED MINIMUM CHARGE
2		PROVISIONS FOR RESIDENTIAL CUSTOMERS OF THE TYPE BEING
3		PROPOSED BY HELCO?
4	A.	No. HELCO is already fairly unique in having a minimum charge to residentia
5		customers of \$20 per month, which is double the monthly customer charge
6		of \$10. Dr. Orens (HELCO T-19) notes in his testimony at page 19 that
7 8 9 10 11 12		Of the fifty high cost utilities reviewed in our survey, all but one have customer charges. However, only two utilities have monthly minimum charges greater than the customer charge. Kauai has a \$12.16 per month minimum bill, with a separate monthly charge of \$9.72. Los Angeles Department of Water and Power (LADWP) has a \$.30 per month customer charge and a \$7 monthly minimum bill.
14 15		By this comparison, the HELCO residential minimum bill that now exists
16		appears to have far exceeded that imposed by most other electric utilities
17		Dr. Orens found in his survey only two utilities with residential rates that
18		differentiate for continuous versus intermittent use and "neither of these
19		utilities had a formula based minimum bill" or a minimum bill charge that
20		exceeded \$16/month for seasonal customers. ³⁹
21		
22	Q.	ARE THERE ALTERNATIVES TO THE MORE COMPLEX ALTERNATIVE
23		SCHEDULE R MINIMUM BILL, THROUGH WHICH HELCO MAY BE ABLE
24		TO RECOGNIZE HIGHER FIXED COST RECOVERY WHEN SERVING

1 INDIVIDUALLY LARGE VACATION HOMES THAT ARE FREQUENTLY 2 **VACANT?** 3 Α. The Consumer Advocate would not object to consideration of revisions to the 4 Residential Schedule R qualification criteria, requiring very large residential 5 connected loads above a specified demand level to be served at HELCO's 6 General Service G/J rates, so as to provide flexibility and higher compensatory 7 customer charges when connecting and serving very large individual homes. 8 9 B. COMMERCIAL AND LIGHTING RATE DESIGN. 10 Q. AT PAGES 20 THROUGH 30 OF HIS TESTIMONY, MR. YOUNG 11 DESCRIBES PROPOSED TARIFF PRICES FOR EACH COMPONENT OF 12 THE COMPANY'S COMMERCIAL AND LIGHTING RATE SCHEDULES G. J. 13 AND F. HAVE YOU DEVELOPED SPECIFIC 14 RECOMMENDATIONS THAT CORRESPOND TO THE CONSUMER 15 ADVOCATES RECOMMENDED OVERALL REVENUE INCREASE? 16 Α. No. The specific rates proposed by HELCO, as explained in Mr. Young's 17 testimony, were designed to produce a significantly larger overall revenue 18 increase than is proposed by the Consumer Advocate. Because the precise 19 amount of revenue increase to be awarded in the Commission's Order is not 20 known, I will limit my testimony regarding commercial and lighting rate design 21 issues to address the broad rate change concepts being proposed by HELCO,

rather than formulate specific alternative tariff price recommendations. The

final rate design required for HELCO will need to produce a much smaller revenue increase, reflecting consideration of ratemaking adjustments being proposed by the Consumer Advocate. The smaller overall rate increase provides an opportunity to moderate the commercial customer impacts associated with the large HELCO-proposed rate increases that are illustrated in Mr. Young's Bill Comparison studies set forth at HELCO-2018, pages 3 through 10.

9 Q. AT HELCO'S PROPOSED RATE LEVELS, HOW WOULD THE CUSTOMER,

10 DEMAND AND ENERGY ELEMENTS OF THE VARIOUS COMMERCIAL

11 TARIFFS BE REVISED?

A. Mr. Young has proposed relatively large percentage increases to the customer charge rate elements for rates Schedules G, J, H and P; extremely large percentage increases in demand charges for Schedule J and P; and energy charge rate increases that are proportionately reduced to these schedules, because of the emphasis upon increasing customer and demand rate elements.

1	Q.	WHAT GENERAL APPROACH DO YOU PROPOSE REGARDING A RATE									
2		DESIGN IMPLEMENTATION PLAN FOR THE REVENUE INCREASES THAT									
3		MAY ULTIMATELY BE APPROVED BY THE COMMISSION?									
4	A.	I propose that the existing structure of Customer Charges, Minimum Charges,									
5		Energy Charges, and Demand Charges within HELCO Rate Schedules G, J,									
6		H, P and F be retained. Then, after accounting for the Commission approved									
7		base fuel energy cost rate as an adjustment to the existing energy rates,									
8		recommend that the demand rate element for Schedules J and P be increased									
9		no more than 30 percent above present rate levels, with all other tariff									
10		elements being adjusted uniformly, in equal percentages, to achieve the									
11		revenue levels required for the overall rate schedule.									
12											
13	Q:	CAN YOU ILLUSTRATE HOW THIS APPROACH WOULD APPLY TO THE									
14		SCHEDULE G GENERAL SERVICE NON-DEMAND RATE?									
15	A.	Yes. If we assume for illustration purposes that overall revenues from									
16		Schedule G customers are to be increased by 4.0 percent, the following									
17		protocol would be followed:									
18		1. Increase the Customer Charge from \$28.00 to \$29.00 for Single-Phase									
19		Service and from \$48.00 to \$50.00 for Three-Phase Service.									
20		2. Increase the Energy Charge from 21.3604 cents/kwh to									
21		22.2148 cents/kwh (plus amounts required to zero-base the ECAC).									
22		3. Retain the Minimum Charge equal to the Customer Charge.									

1 This same basic approach would be applicable to the pricing elements within 2 the other rate schedules. Schedules having demand charges would first be 3 limited to the 30 percent rate increase limitation percentage value for each 4 demand element of the tariff, with an equal percentage increase for all other 5 rate elements after accounting for new revenue for demand rate increases. 40

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Q.

HELCO HAS PROPOSED SIGNIFICANT INCREASES TO THE CUSTOMER CHARGES WITHIN RATE SCHEDULES G, J, H, AND P, AND TO THE DEMAND CHARGES IN SCHEDULES J AND P. AS EXPLAINED IN THE TESTIMONY OF MR. YOUNG AT PAGES 21, 23, 26 and 28. WHY DO YOU NOT SUPPORT THESE LARGE INCREASES IN YOUR RATE DESIGN PROPOSAL?

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Α.

These changes are not required under the lower revenue requirement being recommended by the Consumer Advocate. In addition, large Customer Charge increases are not supported by the Consumer Advocate's cost of service evidence and tend to contribute to unreasonably abrupt rate increase impacts upon lower volume customers in these rate classes.

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HELCO appears to rely upon its calculation of "unit costs" from its embedded COSS to conclude that its proposed large increases in Customer

⁴⁰ The proposed limitation in demand charge increases would permit HELCO's proposed demand charge increases to Rate Schedules H and U, but reduce the increases proposed for Rate Schedules J and P, as more fully described in the testimony that follows.

Charge amounts are reasonable.⁴¹ However, HELCO's calculations of "unit customer costs" is overstated due to the incorrect classification of part of the cost of distribution network poles, lines and transformers as "customer costs," as explained in my COSS testimony. The Consumer Advocate has quantified "unit customer costs" at much lower levels in Exhibit CA-501, which compare favorably to the existing levels of Customer Charge and the Minimum Charge provisions within current tariff prices. For example, the existing Schedule G Customer Charge of \$28.00 per month is reasonable and more than adequate in relation to estimated "Total Customer" costs of \$17.40 per month shown in the "Schedule G" column of Exhibit CA-501 at "TOTAL CUSTOMER."

Regarding customer impacts, HELCO-2018, page 3 illustrates the bill impacts associated with HECO's proposed changes to Schedule G for Single-Phase service. HELCO's proposed rates produce monthly bill increases to low volume customers as high as 15.88%, due largely to the \$7.00 increase in monthly Customer Charge that is being proposed. Finally, large increases in customer charges reduce the level of energy prices and thereby reduce the incentive for small commercial customers to conserve energy. This outcome appears to conflict with the conservation incentive goals noted by HELCO in support of Residential inclining block rates and

For instance, HECO T-20, states at page 24, line 15, "The proposed customer charges of \$39.00 and \$65.00 per month for Single-Phase Service Three-Phase Service, respectively, recover approximately 53% of the class's total customer-related costs at proposed rates, (see HELCO-2007, HELCO-2017)."

1	HELCO's recommendation of no increases in customer charges to Residential
2	customers.

Q. WHY HAVE YOU PROPOSED LIMITING HELCO'S PROPOSED DEMAND
 CHARGE INCREASES FOR RATE SCHEDULES J AND P TO 30 PERCENT
 AT THIS TIME?

A. Commercial customers taking service at relatively low load factors may be adversely impacted by abrupt changes in demand charges. HELCO has proposed to increase the Schedule J General Service demand charge from \$7.00 to \$12.00, an increase of 71 percent. For Schedule P Large Power Service, the proposed demand charge increase is also more than 70 percent. At HELCO-2018, page 5, much larger percentage bill impacts to low load factor Schedule J customers will occur under the Company's proposal, in part due to the large increases in demand charges. For example, a 25 kW Schedule J customer taking only 100 kwh per kw will see bill increases of 18.56 percent, more than double the percentage increase of a customer using 400 kwh per kW.

1 Q. WHAT DOES THE HELCO COST OF SERVICE STUDY TELL US ABOUT
2 DEMAND RATES IN RELATION TO UNIT DEMAND COSTS?

The explanation given by Mr. Young for the large percentage increases proposed for commercial demand charges is simply a reference to the percentage of unit demand cost that would be "recovered" at proposed rates. However, existing and proposed demand charges for Rate Schedules J, H and P are all far below indicated unit cost, as summarized at HELCO-2008. Mr. Young does not explain why large percentage rate increases exceeding 70 percent to move Schedule J and P demand prices toward such costs is needed at this time.

Notably, for Schedule H Commercial Cooking, Heating, Air Conditioning and Refrigeration Service, HELCO has proposed much lower increases in the demand charge from the existing level of \$7.00 to \$9.00, an increase of about 29 percent. Since the indicated unit demand cost for service to Schedule H is nearly the same as the unit demand cost to serve Schedule J customers, I suggest that all commercial demand rate increases be limited to less than 30 percent at this time to mitigate rate shock to low load factor customers. Clearly some movement toward higher demand charges is in order, but gradual movement in the general magnitude of HELCO's proposed change for Schedule H would be more appropriate to avoid potential rate shock.

Α.

⁴³ Id. page 24, line 19 and page 29, line 23.

7		C.	OTHER TARIFF CHANGES.
2	Q.	HEL	CO HAS PROPOSED A LARGE NUMBER OF INDIVIDUAL CHANGES
3		TO I	TS TARIFF TO CLARIFY EXISTING RATE QUALIFICATION CRITERIA
4		DEM	IAND RATCHET PROVISIONS, DISCOUNT TERMS, AND DELIVERY
5		VOL	TAGE PROVISIONS. WHICH OF THESE PROVISIONS DOES THE
6		CON	ISUMER ADVOCATE NOT OPPOSE?
7	A.	The	following changes have been reviewed by the Consumer Advocate and
8		are <u>a</u>	accepted for implementation by HELCO:
9		•	Schedule G modification of availability clause to transfer loads
10			exceeding 5,000 kWh per month in any three months out of a
11			twelve-month period or loads exceeding 25 kW to Schedule J (T-20,
12			page 20);
13		•	Limit Qualification for Schedule J service to less than 200 KW per
14			month, subject to grandfathering of existing Schedule J customers
15			exceeding this limit (T-20, pages 23-24);
16		•	Limit Qualification for Schedule PS service to loads in excess of
17			200 KW per month, subject to grandfathering of existing Schedule P
18			customers not meeting this limit (T-20, pages 28-29);
19		•	Revise Schedule J demand ratchet simplification to conform to the
20			average ratchet provision within existing Schedule P (T-20, page 25):

1		• Reduce supply voltage discount provisions for Schedules G, J, P and
2		Schedule U to conform to HELCO's updated loss study results (T-20,
3		pages 21, 23, 28 and 32);
4		Close Schedule U and Rider T to new customers, since new time of use
5		rate options are being made available (T-20, page 33);
6		Restrict use of existing Rider M so that it cannot be used in conjunction
7		with any other time of use or optional rates (T-20, page 34);
8		Withdrawal of Riders EV-R and EV-C for electric vehicle charging
9		(T-20, page 39); and
10		Re-title the "Returned Check Charge" as a "Returned Payment Charge"
11		to recognize electronic payment options (T-20, page 39).
12		
13	Q.	AT PAGES 40 TO 50 OF HIS TESTIMONY, MR. YOUNG DESCRIBES
14		SEVERAL NEW HELCO TIME OF USE RATE SCHEDULES THAT ARE
15		PROPOSED FOR IMPLEMENTATION. DOES THE CONSUMER
16		ADVOCATE RECOMMEND APPROVAL OF THESE TARIFFS?
17	A.	Yes, subject to conforming the actual rate levels in the tariffs to maintain
18		planned differences in relation to the corresponding sales rates that are
19		implemented. The optional Time of Use ("TOU") rates proposed by HELCO
20		provide customers with an opportunity to lower their energy costs by shifting
21		usage from peak to off-peak periods. HELCO's proposed TOU rates are
22		separated by corresponding Rate Schedule. For example TOU-R

corresponds with sales rate Schedule R and TOU-G corresponds to sales rate Schedule G. The TOU rates provide for modestly higher customer charges than the basic corresponding sales rate to contribute toward the incremental cost of TOU metering and billing, while the energy rates provide a discount from the standard energy rate for kWh delivered during the off-peak period, offset by higher prices for mid-peak and on-peak usage. The usage periods and rate discount/premium ranges that are proposed appear reasonable in relation to marginal costs and existing HELCO load management Rider tariffs, but will need to be carefully examined after some experience is gained with customer participation to evaluate customer and utility impacts. Actual rate element pricing will need to be modified, based upon ultimate revenue requirement levels and to conform to the limitations in proposed customer charge increases and demand charge increases described herein.

1	Q.	HELCO HAS PROPOSED THAT ITS TIME OF USE RATES BE LIMITED TO
2		300 RESIDENTIAL SCHEDULE R METERS, 100 SCHEDULE G METERS,
3		50 SCHEDULE J METERS AND 12 SCHEDULE P METERS IN ORDER TO
4		"MANAGE PARTICIPATION IN THESE OPTIONAL RATES WHILE
5		COLLECTING DATA FOR FUTURE TIME-OF-USE RATE DESIGN
6		OFFERINGS."44 IS THIS A REASONABLE PROPOSAL?

Yes. Existing HELCO automated billing system capabilities do not enable TOU billing to be performed automatically and the replacement CIS billing system is not yet completed. Limiting participation in the TOU rates until CIS capabilities are expanded will help to contain costs and problems that may arise in special billing for TOU sales. Also, the Company has not estimated any revenue impacts from customer participation in TOU rates, so any revenue losses from "successful" TOU load shifting by customers would negatively impact HELCO financially and limiting participation in TOU will serve to mitigate such impacts. Help to contain capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replacement CIS billing system capabilities do not enable to the replaceme

The Consumer Advocate also reserves the right to monitor and evaluate these TOU pricing initiatives as more information about customer participation becomes available and recommends that HELCO be required to

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Α.

HELCO T-20; page 41, line 14; page 42, line 20; page 44, line 9; page 46, line 2; and page 48, line 18.

See HELCO T-7, page 22 for a discussion of the status of the new CIS system.

⁴⁶ HELCO T-20, page 41, lines 21-24.

make a reporting of TOU participation rates and customer/Company revenue 2 impacts and related load shifting results after 24 months of experience, along with a detailed plan for any modifications of the TOU rates, phasing out of 4 meter limits for broadened customer participation as well as advertising and promotion of the TOU rates.

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7 Q. HELCO PROPOSES THAT ITS EXISTING RATE SCHEDULE H FOR 8 COMMERCIAL COOKING AND HEATING BE CLOSED TO NEW 9 CUSTOMERS EXCEPT FOR PERMITTED RE-LOCATION OF EXISTING 10 SCHEDULE H SERVICE. DOES THE CONSUMER ADVOCATE SUPPORT 11 THESE CHANGES?

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A.

Yes. Schedule H is HELCO's only rate schedule that is tied to the specific customer end uses of the energy, which is discussed under the caption "Schedule H - Commercial Cooking and Water Service" at page 26 of Mr. Young's testimony. Rate Schedule H is available to commercial electric cooking, heating (Including heat pump waterheaters), air conditioning and refrigeration service, where the voltage supplied by the Company is less than 600 volts. Schedule H appears to have been a promotional rate, since the customer demand for billing purposes is discounted based upon the connected heating, cooking, and water heating demands. This rate schedule

presently serves only about 264 customers.⁴⁷ One component of the rate that provided for a measured monthly demand value was referred to as Schedule K service and was "closed to new customers after October 9, 1992."

The Consumer Advocate supports HELCO's recommendation that Schedule H be closed to new customers at this time because HELCO has demonstrated no need to maintain any end-use rate schedules of this type, there is no need for any promotional pricing of electricity given the Company's current capacity position relative to growing demand levels and HELCO is unable to identify or explain whether any cost justification exists today to support billing exclusions for any identified HELCO end-uses of energy.⁴⁸

Α.

Q. SHOULD CUSTOMERS TAKING SCHEDULE H SERVICE BE REQUIRED
TO MIGRATE TO OTHER RATE SCHEDULES IN THE FUTURE?

Yes. Company should be required to develop and present a definitive rate migration plan for consideration in its next general rate case to systematically move all existing Schedule H customers onto the other rates schedules.

T-20, page 27, forecasted number of Schedule H customers for test year 2006.

⁴⁸ See HELCO response to CA-SIR-19.

1 D. MISCELLANEOUS SERVICE RULES/RATES.

- 2 Q. WHAT IS PROPOSED BY HELCO WITH REGARD TO MISCELLANEOUS
- 3 SERVICE CHARGES?
- 4 A. Within its Commission-approved Rules, the Company charges for certain
- 5 service-related activities in addition to the prices charged for electric service.
- These charges include fees for a Returned Check Charge, Field Collection
- 7 Charge, Service Establishment Charge and a Late Payment Charge, as
- 8 provided for in Rule 8 (see HELCO-108). Other than changing the labeling of
- 9 the "Returned Check Charge" to a "Returned Payment Charge," HELCO
- proposed no changes to its miscellaneous service charges in its filing.⁴⁹ When
- asked why no price changes were proposed, HELCO replied that it "did not
- conduct cost studies due to limited manpower resources" and that "[t]here was
- no work done to determine that no changes should be made to any
- 14 miscellaneous service prices."⁵⁰

- 16 Q. DOES THE CONSUMER ADVOCATE AGREE THAT HELCO'S
- 17 MISCELLANEOUS SERVICE CHARGES SHOULD NOT BE CHANGED?
- 18 A. No. Even though cost study support was not undertaken by HELCO in this
- docket, such cost information was prepared by HECO and submitted to the

⁴⁹ HELCO T-20, pages 39-40.

HELCO responses to CA-IR-221 and 318.

Commission in Docket No. 04-0113. The HECO cost studies supported a conclusion that the existing HECO prices for these activities are likely to not recover the costs incurred to provide the services. I believe that the HECO cost studies are indicative of unreasonably low prices for such services in the existing HELCO tariff and recommend that HELCO prices for these services be moved to the HECO-recommended price levels at this time, and that HELCO be required to submit cost study support for these services within its next rate case filling. Without increased pricing for such services, the expenses that are incurred and not recovered by HELCO when service is established or reconnected, or when a field collection or returned payment is encountered, will be borne by the Company's general body of ratepayers.

Α.

Q. TO WHAT EXTENT DOES HECO PROVIDE THE SAME TYPES OF SERVICES, FOR WHICH THERE ARE CHARGES IN ITS TARIFF?

HECO's tariff contains the same general provisions for service-related charges that exist for HELCO, including the Service Establishment Charge, the Field Collection Charge and the Returned Check Fee. To support these proposed changes, HECO had conducted cost studies that were generally supportive of the new proposed price levels for miscellaneous services and the Consumer Advocate found HECO's proposals to be reasonable in terms of such cost support as well as customer impact. In addition, the HECO-proposed increased miscellaneous service charge amounts were noted to be consistent

with the miscellaneous charges of other utility companies for similar services. For instance, HECO's proposed Service Establishment Charge of \$20 during normal business hours and \$45 for expedited same day service compare reasonably to charges of The Gas Company at \$30 for re-connection service, with a \$45 charge for such service other than during normal business hours. Field Collection charges proposed by HECO of \$20 were equal in amount to comparable charges imposed by The Gas Company. With respect to returned payment charges, HECO's proposed \$16 charge was conservatively low in relation to The Gas Company's rate of \$25.

The Stipulated Settlement Letter in HECO Docket No. 04-0113 noted in Exhibit II, page 13 that "There were no issues with respect to HECO's proposed changes to terms and conditions in rates and riders, the proposed changes to Rule No. 4 (Standard Customer Retention Rate), the proposed changes to the non-sales related charges such as the Returned Checks Charge, Field Collection Charge, and Service Establishment Charge..."

The Gas Company, L.L.C. Original Tariff Sheet No. 32, Issue August 8, 2003. The Gas Company also charges a \$7.50 service charge to re-open an account that has been closed temporarily at customer request.

- 1 Q. HOW DO THE HELCO SERVICE CHARGES COMPARE TO THE
 2 PROPOSED LEVELS OF COMPARABLE HECO CHARGES THAT WERE
 3 ACCEPTED BY THE CONSUMER ADVOCATE IN SETTLEMENT IN THE
- 5 A. The HELCO prices for these activities, in comparison to the HECO-proposed prices that were accepted in settlement of Docket No. 04-0113, are as follows:

Rule No. 8 Charges	HELCO Price	HECO Settlement Price
Service Establishment	\$15.00	\$20.00
Reconnection Charge	\$10.00	\$25.00
Returned Check Charge	\$15.00	\$16.00
Field Collection Charge	\$15.00	\$20.00

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HECO CASE?

In its new rate case filing, HECO has proposed retention of these charges at the levels reached in the settlement of Docket No. 04-0113, except for Returned Check Charge, which is proposed to be re-labeled as a Returned Payment Charge (as proposed by HELCO) and is to be further increased from \$16.00 to \$22.00 based upon more current bank charges.⁵²

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14 Q. ARE THE COSTS INCURRED BY HECO TO PROVIDE MISCELLANEOUS
15 SERVICES COMPARABLE TO THE COSTS THAT HELCO WOULD INCUR?
16 A. Yes. HELCO uses common customer support systems and comparable
17 personnel classifications to perform these services. In the last HECO rate

⁵² See HECO T-20, page 49, in Docket No. 2006-0386.

case, the cost studies used to justify higher service charges⁵³ were based upon HECO standard hourly labor rates as of 2005. The comparable HELCO hourly labor rates for the 2006 test year are slightly higher than the cost levels used by HECO to justify the price increases that were agreed upon.⁵⁴ Therefore, I believe the new HECO prices are reasonable for use by HELCO in the absence of current cost study data for 2006.

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E. RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAM FOR AFFORDABLE HOMES ("REEEPAH") TARIFF.

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11 Q. AT PAGES 50-52 OF HIS TESTIMONY, MR. YOUNG DESCRIBES A 12 PROPOSED NEW "REEEPAH CLAUSE" TARIFF THAT HE WOULD 13 IMPLEMENT TO INITIALLY COLLECT \$500,000 FOR THE NEW REEEPAH 14 PROGRAM, AND WOULD THEN USE IN FUTURE PERIODS TO MODIFY 15 PROGRAM FUNDING LEVELS. SHOULD THIS TARIFF BE APPROVED? 16 Α. No. The Consumer Advocate has opposed creation of HELCO's new REEEPAH program, as explained in my CA-T-1 testimony. 55 Without approval 17 18 by the Commission of the REEEPAH program, there is no need for creation of 19 a new REEEPAH funding tariff for this program.

These studies appeared at HECO WP-2201, pages 1-27 in Docket No. 04-0113.

The BUOC office/clerical rate of \$24.90 for HELCO in 2006, as provided in response to CA-IR-112 at page 3 is slightly higher than HECO's standard hourly \$23.07 cost for office personnel in 2005.

⁵⁵ CA-T-1, pages 56-61.

1 F. POWER FACTOR RATE ELEMENTS. 2 Q. WHAT ARE POWER FACTOR CREDITS AND HOW SHOULD THEY BE 3 ADJUSTED AS PART OF THE RATE CHANGES APPROVED IN THIS 4 DOCKET? 5 Α. As discussed in Mr. Herz's testimony (CA T-2), HELCO is presently crediting 6 or charging commercial customers when their measured power factor is above 7 or below 85 percent. The Power Factor tariff provisions specify a different rate 8 adjustment of 0.10 percent for Schedule J versus 0.15 percent for Schedule P. 9 applied to the customer's monthly energy and demand charge for each 1 percent of average monthly power factor above or below 85 percent.⁵⁶ 10 11 Power factor rate credits were at issue in the most recent HECO rate 12 case, Docket No. 04-0113 and were addressed in the Stipulated Settlement 13 Letter dated September 16, 2005 at Exhibit II, page 12 as follows: 14 b. Intra-class Rate Design – With respect to intra-class rate 15 design, the Parties have agreed that: 16 1. HECO will develop and submit a plan to freeze or 17 cost justify Schedule H in HECO's next rate case 18 in order to address the Consumer Advocate's 19 proposal with respect to Schedule H; 20 2. HECO will conduct a cost study to support 21 cost-based Power Factor Credits or Charges in 22 HECO's next general rate case, in order to 23 address the Consumer Advocate's proposal, 24 which HECO opposed in rebuttal and DOD 25 opposed, to eliminate the existing Power Factor 26 credits for Classes J, PS, PP and PT and to

establish a Power Factor penalty. The DOD also

did not initially concur with the need to conduct

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1 such a study but in the interest of compromise and 2 to settle this issue, agreed to allow inclusion of this 3 provision. 4 Unfortunately, the recently filed HECO "next general rate case" (Docket 5 6 No. 2006-0386) does not include the promised cost study support to support 7 the power factor tariff, as explained by HECO T-20 (Mr. Young) in HECO T-20 8 at page 16: 9 HECO has not completed such a study at this time. HECO's preliminary analysis of the power factor issue indicates that the 10 11 cost basis for power factor is in fact complex and subject to 12 variation depending on the needs of the HECO system to meet customer var-hr ("vars") requirements. HECO supplies vars 13 14 through capacitor banks that are installed on the transmission 15 and distribution system, and also through generation at the 16 power plants. The amount of vars provided through generation 17 varies with the total vars demand, with whether the capacitor 18 banks are switched on or off, and with the maintenance of 19 transmission and distribution lines, among other considerations. 20 The customer demand for vars depends on both amount of load 21 and the physical location of the load. 22 23 24 WHY ARE HELCO'S POWER FACTOR ADJUSTMENT VALUES HIGHER Q. 25 FOR SCHEDULE P VERSUS SCHEDULE J? 26 Α. This is not clear and is of concern to the Consumer Advocate, since the 27 adjustment at 0.10 percent for Schedule J already appeared to be excessive 28 when this value was examined in the last HECO rate case and the even higher

HELCO Schedule P power factor adjustment of 0.15 percent may be more

excessive. The costs incurred by a utility in relation to power factor issues are

to provide vars, which increase fuel expense and/or add facility costs to install

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equipment such as capacitors to manage voltage and reconductoring to replace lost capacity; which costs are not different whether the power factor effects arise within Schedule J or Schedule P load characteristics. There is no reason why a different power factor tariff value should apply between HELCO Schedule P and Schedule J.

According to the Company's response to CA-IR-243, HELCO's power factor adjustment based on 85% power factor at the 0.15 percent value has been included in the Schedule P rate of HELCO's predecessor since at least 1940, and was subsequently adopted into HELCO's Schedule J when Schedule J became a separate rate schedule (but at the lower 0.10 adjustment value). The power factor for HELCO's Schedule J is the same power factor for HECO's Schedule J and the Company is not aware of any cost of service analyses or other studies that were prepared to support the power factor adjustment.⁵⁷

HECO's comparable power factor adjustment provision has been in HECO's tariffs since before the 1930's and the demand/energy adjustment rate was revised from 0.15% to 0.10% effective July 22, 1980, per PUC Decision & Order No. 6275 in Docket No. 3705. Based upon the review and testimony of Consumer Advocate witness Mr. Herz and the absence of cost justification by HELCO for the significant power factor credits now being

provided to customers, the Consumer Advocate proposes that HELCO's Schedule P power factor credits now also be reduced, as found reasonable for HECO in 1980, to conform with existing HELCO Schedule J, as well as HECO Schedules J, PS, PP and PT adjustments at the 0.10% value, pending further analysis and cost support. HELCO should be required in its next rate filing to conduct studies of its incurred costs associated with reactive power issues and propose a cost-based schedule of charges to customers that impose reactive loads and related costs upon the utility.

Α.

10 Q. WHAT IS THE ANNUAL REVENUE AMOUNT ASSOCIATED WITH THE
11 POWER FACTOR CREDIT REDUCTION FOR SCHEDULE P?

Reducing the Schedule P Power Factor Credit from .15 percent to .10 percent would reduce the credits to Schedule P customers at present rates by 1/3 of the existing amount of \$515,800, increasing revenues at present rates by \$172,000.⁵⁸ This change in revenues at present rates has been considered within the Consumer Advocate's proposed rate spread to recover the rate increase needed in this proceeding.

1 G. STANDBY TARIFF RATES.

- 2 Q. WHAT IS PROPOSED BY HELCO WITH REGARD TO STANDBY SERVICE
- 3 AVAILABLE TO CUSTOMERS WITH ALTERNATIVE SOURCES OF
- 4 POWER?
- 5 A. HELCO has an existing tariff referred to as "Rider A" that the Company
- 6 proposes to revise as described at page 35 of Mr. Young's testimony
- 7 (HELCO T-20). The proposed revisions involve separate Rider A rates for
- 8 Schedule J and Schedule P customers at prices generally higher than existing
- 9 rates, based upon the Company's calculated cost of service and the
- 10 "derivation that the Company used in its Final Standby Service Rider Proposal
- in Docket No. 99-0207." These calculations are shown at HELCO-WP-2001,
- page 79 and involve percentage allocations of generation and demand unit
- costs to Standby customers from that earlier Docket. Mr. Young's testimony
- 14 also acknowledges that the existing Rider A rate will be affected by the
- proceedings in Docket No. 03-0371 involving distributed generation ("DG").

- 17 Q. HAS HELCO MADE A FILING OF PROPOSED NEW STANDBY RATES AS
- 18 REQUIRED BY THE COMMISSION IN ITS DECISION AND ORDER
- 19 NO. 22248 IN DOCKET NO. 03-0371?
- 20 A. Yes. Relying upon its calculated cost of service in this rate case docket, as
- 21 well as certain cost allocation principles from the prior Rider A derivation
- 22 discussed above, HELCO and its affiliated electric utilities made a filing of

1		proposed new Standby rates. However, the Commission received comments
2		from several parties and, by its Order No. 23171 issued on December 28,
3		2006, and initiated a new proceeding to investigate the standby rates
4		proposed by the HECO companies.
5		
6	Q.	WHAT DO YOU RECOMMEND WITH REGARD TO THE EXISTING RIDER A
7		TARIFF AND THE NEWLY PROPOSED HELCO STANDBY RATES THAT
8		WOULD REPLACE RIDER A?
9	A.	I recommend that HELCO's existing Rider A be retained in its present form
10		with no changes to price levels within this rate case proceeding. Any changes
11		to the tariff structure, cost allocations or pricing of Standby service should be
12		deferred until the Commission's new investigation in Docket No. 2006-0497 is
13		completed and any issues associated with cost allocation principles have been
14		resolved.
15		
16	Q.	DOES THIS COMPLETE YOUR TESTIMONY REGARDING COST OF
17		SERVICE AND RATE DESIGN?
18	Α.	Yes.

HAWAII ELECTRIC LIGHT COMPANY, INC. TEST YEAR 2006, DOCKET NO. 05-0315 DIRECT CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

	RESIDENTIAL SERVICE	GEN SERV NON-DMD	GEN SERV DEMAND	COMMERCIAL SERVICE	LARGE POWER	STREET LIGHTING	TOTAL
REVENUES	R	<u>G</u>	J	<u>н</u>	P	F	SYSTEM
SALES REVENUE	127,914.3	33,534.6	94,171.5	4,740.0	57,205.4	1,233.1	318,798.8
OTHER OPERATING REVENUE	598.6	71.4	95.0	11.8	127.4	0.2	904.4
TOTAL OPERATING REVENUE	128,512.9	33,606.0	94,266.5	4,751.8	57,332.7	1,233.3	319,703.2
EXPENSES							
FUEL AND PURCHASED POWER	67,902.1	15,283.4	55,214.4	2,682.4	36,422.4	686.2	178,191.0
OTHER PRODUCTION COSTS	14,655.3	3,037.9	10,707.3	547.2	5,692.7	172.8	34,813.2
TRANSMISSION	966.5	200.3	706.1	36.1	375.4	11.4	2,295.9
DISTRIBUTION	3,174.1	621.9	1,706.2	91.6	623.1	28.6	6,245.4
CUSTOMER ACCOUNTS	2,482.9	550.0	125.5	14.7	5.8	6.7	3,185.6
UNCOLLECTIBLES	283.1	54.3	50.4	0.0	0.0	0.0	387.8
CUSTOMER SERVICE	788.4	104.1	342.1	14.9	238.0	0.0	1,487.6
ADMIN AND GENERAL	5,797.1	1,185.4	3,595.7	186.3	1,837.1	58.0	12,659.7
WAGE ROLLBACK	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING & MAINT EXPENSE	96,049.6	21,037.3	72,447.8	3,573.2	45,194.5	963.7	239,266.1
DEPRECIATION EXPENSE	13,836.8	2,770.0	7,644.1	406.7	3,497.9	129.7	28,285.1
TAXES OTHER THAN INCOME TAXES	12,091.3	3,125.1	8,734.9	441.0	5,270.1	115.5	29,777.9
INCOME TAXES	672.2	2,234.3	937.6	67.3	768.8	-9.8	4,670.4
AMORTIZED INVESTMENT TAX CREDIT	-240.8	-47.6	-140.5	-7.4	-62.2	-2.4	-501.0
GAIN ON SALE OF PROPERTY	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INTEREST ON CUSTOMER DEPOSITS	25.8	5.1	16.3	0.8	7.5	0.3	55.8
INVENTS! ON COSTONER DEFOSITS	25.8		10.3	0.8			75.0
TOTAL OPERATING EXPENSES	122,434.8	29,124.2	89,640.2	4,481.5	54,676.6	1,197.0	301,554.3
PRESENT RETURN	6,078.0	4,481.8	4,626.3	270.3	2,656.2	36.4	18,148.9
RATE BASE							
GROSS PLANT IN SERVICE	373,051.1	73,922.1	211,410.6	11,234.7	93,774.0	3,585.5	766,978.1
DEPRECIATION BALANCE	-163,488.6	-32,548.2	-88,010.2	-4,714.1	-39,207.6	-1,521.5	-329,490.2
NET PLANT IN SERVICE	209,562.5	41,374.0	123,400.4	6,520.6	54,566.4	2,064.0	437,487.9
PROPERTY HELD FOR FUTURE USE	27.2	5.6	19.8	1.0	10.5	0.3	64.5
FUEL INVENTORY	2,728.8	614.2	2,218.9	107.8	1,463.7	27.6	7,161.1
MATERIALS AND SUPPLIES	1,545.2	312.6	820.3	43.9	384.9	14.2	3,121.0
WORKING CASH	899.1	199.8	636.4	31.4	407.9	8.2	2,182.8
CONTRIBUTIONS & ADVANCES	-47,856.6	-9,324.1	-21,662.5	-1,200.5	-8,235.9	-395.9	-88,675.5
DEFERRED INCOME TAXES	-12,557.0	-2,485.8	-7,455.4	-393.3	-3,332.0	-124.5	-26,348.0
UNAMORT INVEST TAX CREDITS	-5,654.6	-1,119.4	-3,357.3	-177.1	-1,500.5	-56.0	-11,865.0
OTHER RATE BASE DEDUCTIONS	11,638.6	2,310.4	6,632.3	352.1	2,964.3	112.3	24,010.0
TOTAL RATE BASE	160,333.2	31,887.2	101,253.0	5,285.9	46,729.4	1,650.1	347,138.8
RATE OF RETURN (%)	3.79%	14.06%	4.57%	5.11%	5.68%	2.20%	5.23%
ROR AS % OF SYSTEM ROR	72.51%	268.84%	87.39%	97.79%	108.72%	42.17%	100.00%

HAWAII ELECTRIC LIGHT COMPANY, INC. TEST YEAR 2006, DOCKET NO. 05-0315 DIRECT SUMMARY OF PRESENT AND PROPOSED CLASS REVENUES AND RATES OF RETURN

	RESIDENTIAL SERVICE	GEN SERV NON-DMD	GEN SERV DEMAND	COMMERCIAL SERVICE	LARGE POWER	STREET LIGHTING	TOTAL
DESCRIT DEVENHES (\$000a)	R	<u>G</u> _		<u>H</u> _	P	<u> </u>	SYSTEM
PRESENT REVENUES (\$000s) SALES REVENUE	127,914.3	33,534.6	94,171.5	4,740.0	57,205.4	1,233.1	318,798.8
OTHER OPERATING REVENUE	598.6	71.4	95.0	11.8	127.4	0.2	904.4
TOTAL OPERATING REVENUE	128,512.9	33,606.0	94,266.5	4,751.8	57,332.7	1,233.3	319,703.2
PROPOSED REVENUES (\$000s)							
SALES REVENUE	135,071.8	34,678.5	99,727.5	5,017.8	59,501.7	1,314.8	335,312.1
OTHER OPERATING REVENUE	685.8	81.5	107.3	13.5	145.8	0.2	1,034.1
TOTAL OPERATING REVENUE	135,757.6	34,760.0	99,834.8	5,031.3	59,647.5	1,315.0	336,346.2
PROPOSED INCREASE (\$000s)				0			
SALES REVENUE	7,157.5	1,143.9	5,556.0	277.8	2,296.4	81.7	16,513.3
OTHER OPERATING REVENUE	87.3	10.1	12.2	1.7	18.4	0.0	129.7
TOTAL OPERATING REVENUE	7,244.7	1,154.0	5,568.3	279.5	2,314.8	81.7	16,643.0
PROPOSED INCREASE (%)							
SALES REVENUE	5.60%	3.41%	5.90%	5.86%	4.01%	6.63%	5.18%
OTHER OPERATING REVENUE	14.58%	14.14%	12.89%	14.23%	14.46%	0.00%	14.34%
TOTAL OPERATING REVENUE	5.64%	3.43%	5.91%	5.88%	4.04%	6.62%	5.21%
REVENUE INCREASE INDEX (SYSTEM = 100)							
SALES REVENUE INDEX	108.03%	65.85%	113.90%	113.15%	77.50%	127.92%	100.00%
OTHER OPERATING REVENUE INDEX	101.65%	98.63%	89.89%	99.22%	100.82%	0.00%	100.00%
TOTAL OPERATING REVENUE INDEX	108.29%	65.96%	113.47%	112.98%	77.56%	127.26%	100.00%
RATE OF RETURN ON RATE BASE (%)							
PRESENT RATE OF RETURN	3.79%	14.06%	4.57%	5.11%	5.68%	2.20%	5.23%
PROPOSED RATE OF RETURN	6.37%	16.21%	7.73%	8.16%	8.54%	5.02%	7.99%
RATE OF RETURN INDEX (SYSTEM = 100)	wa e	***		05 501	100 500	40.1504	100 000
PRESENT RATE OF RETURN INDEX	72.51% 79.79%	268.84%	87.39%	97.79%	108.72% 106.99%	42.17% 62.87%	100.00% 100.00%
PROPOSED RATE OF RETURN INDEX	19.19%	202.96%	96.76%	102.18%	100.99%	02.87%	100.00%
AVERAGE SALES REVENUE (¢ / KWH) PRESENT	29.379	34.219	26.535	27.558	24.026	28.025	27.770
PROPOSED	31.022	35.386	28.100	27.338 29.17 <u>3</u> _	24.990	29.882	29.208
	31.022	22.200	20.100	27.170	2.,,,,		27.500
INCREASE	1.644	1.167	1.566	1.615	0.964	1.857	1.438
ENERGY SALES (MWH)	435,400.0	98,000.0	354,900.0	17,200.0	238,100.0	4,400.0	1,148,000.0

HAWAII ELECTRIC LIGHT COMPANY, INC. TEST YEAR 2006, DOCKET NO. 05-0315 DIRECT UNIT FUNCTIONALIZED CLASS SALES REVENUES AT PROPOSED RATES

		RESIDENTIAL SERVICE	GEN SERV NON-DMD	GEN SERV C	COMMERCIAL SERVICE	LARGE POWER	STREET LIGHTING	TOTAL
ENERGY	UNITS	R	<u> </u>		<u> </u>	<u>P</u>	F	SYSTEM
PRODUCTION	¢/kwh	- 17.183	17.324	17.163	17.209	16.885	17.167	17.127
<u>DEMAND</u>								
PRODUCTION	\$/kW/mo	\$9.06	\$16.68	\$21.52	\$23.22	\$2 6.90	\$ 34.41	\$13.96
TRANSMISSION	\$/kW/mo	\$1.57	\$3.99	\$4.00	\$4.38	\$5.15	\$5.59	\$2.62
DISTRIBUTION PRIMARY								
SUBSTATIONS PRIMARY LINES	\$/kW/mo \$/kW/mo	\$0.60 \$1.70	\$1.46 \$3.36	\$1.46 \$3.91	\$1.63 \$4.35	\$1.63 \$4.29	\$2.30 \$6.73	\$0.95 \$2.55
PRIMARY DEMAND	\$/kW/mo	\$2.30	\$4.82	\$5.36	\$5.98	\$5.92	\$9.03	\$ 3.50
DISTRIBUTION SECONDARY								
SECONDARY LINES LINE TRANSFORMERS	\$/kW/mo \$/kW/mo	\$1.01 \$1.11	\$1.73 \$2 .91	\$1.47 \$1.81	\$1.75 \$2.18	\$0.70 \$0.89	\$2.27 \$2.26	\$1.15 \$1.41
SECONDARY DEMAND	\$/kW/mo	\$2.12	\$ 4.64	\$3.28	\$ 3.93	\$1.59	\$4.52	\$ 2.56
DISTRIBUTION DEMAND	\$/kW/mo	\$4.42	\$9.46	\$8.64	\$9.91	\$ 7.51	\$13.55	\$6.06
TOTAL DEMAND	\$/kW/mo	\$15.05	\$30.14	\$ 34.17	\$37.51	\$39.56	\$53.56	\$22.63
TOTAL DEMAND AND ENERGY	¢/kwh	28.884	33.088	27.717	28.667	24.815	29.468	28.037
CUSTOMER								
PRIMARY LINES SECONDARY LINES LINE TRANSFORMERS SERVICES METERS STREET LIGHTING CUSTOMER ACCOUNTS UNCOLLECTIBLES CUSTOMER SERVICE TOTAL CUSTOMER	\$/CUST/mc \$/CUST/mc \$/CUST/mc \$/CUST/mc \$/CUST/mc \$/CUST/mc \$/CUST/mc	\$0.00 \$0.00 \$3.42 \$2.14 \$0.00 \$5.06 \$0.44 \$1.59	\$0.00 \$0.00 \$0.00 \$4.68 \$4.67 \$0.00 \$6.38 \$0.47 \$1.19	\$0.00 \$0.00 \$0.00 \$7.44 \$24.53 \$0.00 \$10.08 \$3.42 \$27.17	\$0.00 \$0.00 \$0.00 \$5.16 \$8.36 \$0.00 \$6.99 \$0.00 \$6.98	\$0.00 \$0.00 \$0.00 \$12.55 \$63.16 \$0.00 \$11.90 \$0.00 \$483.02	\$0.00 \$0.00 \$0.00 \$3.36 \$1.97 \$0.00 \$6.53 \$0.00 \$0.00	\$0.00 \$0.00 \$0.00 \$3.70 \$3.05 \$0.00 \$5.37 \$0.50 \$2.48
TOTAL UNIT COST	¢/kwh	31.022	35.386	28.100	29.173	24.990	29.882	29.208
UNITIZING FACTORS	, · · · · · · · · · ·	- · · ·		3				
ENERGY SALES SUM OF CUSTOMER DEMANDS AVERAGE ANNUAL CUSTOMERS	MWH MW (N-C) NUMBER		98,000 512.6 10,789	354,900 1,096.2 1,559	17,200 52.5 264	238,100 477.3 61	4,400 10.1 128	1,148,000 5,533.4 74,174

Federal Energy Regulatory Commission Electric Rates and Corporate Regulation Washington, D.C. 20426

Federal Energy Regulatory Commission Electric Rate Handbook



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It should also be noted that common plant and intangible plant have been analogized to general plant and functionalized on the basis of labor ratios. KCPL, 21 FERC at 65,035;

Delmarva, 17 FERC at 65,204; Philadelphia Electric, 10 FERC at 65,355-6.

Another issue that has arisen is the calculation of the labor ratios. Usually, the labor ratio consists of total labor costs in the denominator with the labor costs associated with a particular category, such as production, in the numerator where part of the expenses are being functionalized into that particular category. In a number of proceedings, companies have attempted to change the ratio by only including production, transmission, and distribution-related labor costs in the denominator; thus excluding customer service related labor costs. This, however, has been rejected.

KCPL, 21 FERC at 65,033-34.

B. Classification

After functionalizing, the next step is to classify those expenses as either demand, energy, or customer-related. The classification issues most frequently litigated are: (1) whether the predominance method should be used; that is — if an account is predominantly energy (or demand) related, should it be classified as 100% energy (or demand) or some lesser percentage; and (2) the proper classification scheme for production O&M accounts. These issues will be discussed below.

Predominance method

Staff for a number of years has used a method called the predominance method for classifying production O&M accounts.

Under this method if an account is predominantly (51-100%) energy-related, it will be classified as energy. The same is also true with respect to demand related costs. This method has been repeatedly adopted by the Commission. See e.g.,

Arizona Public Service Company, 4 FERC ¶ 61,101 at 61,209-10 (1978); Illinois Power Company, Initial Decision, 11 FERC ¶ 63,040 at 65,255-6 (1980), affirmed, 15 FERC ¶ 61,050 at 61,093 (1981);

Kansas City Power & Light Company, Initial Decision, 21 FERC ¶ 63,003 at 65,037 (1982), affirmed, 23 FERC ¶ 61,262 (1983);

Minnesota Power & Light Company, Opinion No. 86, 11 FERC ¶ 61,312 at 61,648-9 (1980).

It should be noted, though, that if a company is able to justify a percentage split, such as 70-30, in an account, then that split may be accepted. However, in light of the Commission precedent on this subject, any party proposing a deviation from the predominance method has an especially heavy burden to carry.

2. Classification of production O&M accounts

In addition to the Commission's adoption of Staff's predominance method, the Commission has adopted Staff's classification index of production O&M accounts. Arizona Public Service Company, 4 FERC at 61,209-10; KCPL, 21 FERC at 65,037; Minnesota Power & Light Company, 11 FERC at 61,648-9. Under this

fication index the production OsM accounts are classified as follows:

CLASSIFICATION OF PRODUCTION EXPENSES

of Accounts'	1	Classi:	fication
Account No.	Description	Demand	Energy
•	Steam Power Generation		
	Operation		•
• 500	Operation supervision		
	and engineering	X	
501	· Fuel		X.
502	Steam expenses	X	
503	Steam from other sources		X
504	Steam transferred-Cr.	nan a	X
505	Electric expenses	X	2
506	· Miscellaneous steam		
	power expenses	X.	
507	Rents	. X	÷.
	Maintenance		•
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant	,	X
\$13	Electric plant	-	X
514 .	Miscellaneous steam		4.0
,	plant,	x	
	Nuclear Power Gameration		•
	Operation		
517	Operation supervision	••	
• •	and engineering	· X	
518	Fuel		x
, 519	Coolants and water	X	
520 .	Steam expenses	X	
\$23	Electric expenses	X	
524	Miscellaneous nuclear	•	
	power expenses	X ·	
\$25	Rents	X	
•	Maintenance		
\$28	Supervision and engineering	,	x
\$29	Structures	X	
\$30	Reactor plant equipment		×
531	Electric plant		X
532	Miscellaneous nuclear	•	
•	plant	X	

Uniform System		Classification	
Account No.	Description	Demand	Energy
	 -	•	
,	Hydraulic Power Generation		·
•	Operation		•
			•
· 535	Operation supervision	٠	
	and engineering	X	
536	Water for power,	X .	
537	Hydraulic expenses	X	,
538	Electric expenses	X	
539	Miscellaneous hydraulic		
	boner exberses	X	_
· 540	Rents	X	·
	Maintenance		
541	Supervision and engineering	x	
542	Structures	X	
543	Reservoirs, dams and	-	
	waterways	· x	
544	Electric plant		x
545	Miscellaneous hydraulic	•	
	plant	x	
	Other Power Generation		
	Operation		
P16			
546	Operation Supervision	_	_
	and engineering	X	
547	Fuel		X
548	Generation expenses	X	
549	Miscellaneous other		
	power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	x	
552	Structures	Ï	
553	Generating and electric	-	
	equipment	X	
554	Miscellaneous other power		
	generation plant	X	•
	Other Power Supply Expenses		
555	Purchased power		As billed
556	System control and		ve bitted
	load dispatching	X	
557	Other expenses	X	
	Armer cyhendes	A	

While this classification index may not be appropriate for every utility, any party advocating a deviation from this index has a heavy burden to overcome.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. The allocation of these cost categories, with particular emphasis on the allocation of demand costs, will be discussed below.

1. Allocation of demand costs

The allocation of demand costs is a complex and often litigated issue. The particular issues that are usually litigated are: (1) which coincident peak (CP) demand allocation method (1 CP, 3 CP, 4 CP, or 12 CP) should be adopted; (2) whether the numerator (CP's) and/or the denominator (total system demands) in the demand allocator have been properly projected; and (3) whether transmission costs should be rolledin and allocated on the same basis. These issues will be discussed below. However, before doing so because of the complexity of the issues, a number of terms will be defined.

a. Definitions

(1) Coincident Peak (CP) demands -

Demands of a particular customer or class occurring at the time of the system peak for a particular time period.

HAWAII ELECTRIC LIGHT COMPANY, INC. TEST YEAR 2006, DOCKET NO. 05-0315 DIRECT

FERC Predominance Method

			HELCO-WP-101(C)		
Predominantly Energy NARUC Account (Non-fuel only)			Amo	unt \$000	Page Ref.
512	Boiler Maintenance	Shipman Hill	\$	847 1,872	page 30
513	Steam Electric Plant Maintenance	Puna Shipman Hill		1,000 403 318	page 31
544	Hydraulic Electric Plant Maintenance	Puna Puueo		60 69	page 33
		Waiau	<u> </u>	35	-
Total For	recast - Non-fuel Energy		\$	4,604	sum of above
Total Forecast- All Non-fuel			\$	23,302	page 43
Energy Ratio of Non-fuel Prod O&M				20%	•
HELCO Projected Non-fuel Production O&M Less: Estimated Consumer Advocate Adjustments			\$ _\$	23,040 (2,000)	
			· \$	21,040	
Reclassification O&M Amount at 20%			\$	4,157	

CERTIFICATE OF SERVICE

ADVOCACY'S DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS was duly served upon the following parties, by personal service, hand delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR § 6-61-21(d).

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DATED: Honolulu, Hawaii, February 21, 2007.

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